PRE-ENGINEERING ASSESSMENTS
OF ENERSOLVE DEMONSTRATION PROJECT
AT CANBRA FOODS LTD., LETHBRIDGE

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submitted to

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Department of Energy, Mines of Resources

CANMET, Energy Research Laboratories

Contract Number: 0SQ83-00238

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Gentlemen:

Re: Enersolve Demonstration Project
Contract No. OSQ83-00238

Attached please find the original plus two (2) copies of our final report entitled "Pre-Engineering Assessments of Enersolve Demonstration Project" at Canbra Foods Ltd., Lethbridge, dated 84-06-29. The final report incorporates any changes required as a result of your comments on the draft report.

As per the draft report, Stage I includes all measured test data and efficiencies calculated from this data for the boiler plant as well as economic evaluations of two suggested additions to the boilers based on an assumed average boiler loading of 67% of design capacity. The 67% loading appears to be reasonable based on the latest Canbra Foods data received. Estimates and schedules for Stage II and III are also included as per the draft report.

Should you have any further questions, please do not hesitate to contact the writer.

Yours very truly,

J.R.C. Harding
Assistant Manager, Thermal Division
Western Region

JSK/jj
Encls.
cc: Mr. D.O. Outhouse/Mr. J. Robinson
Mr. J.S. Kestner
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EXECUTIVE SUMMARY

This study report reviews and evaluates potential energy savings for two existing natural gas fired process steam boilers at the Canbra Foods Ltd. plant at Lethbridge, Alberta. The study includes an efficiency test of each boiler, an analysis of potential areas where efficiency might be improved and an evaluation of the major changes required to improve the overall efficiency. The study conclusions are summarized as follows:

Since both boilers are of a fairly old vintage (Boiler #1 - installed in 1959 and Boiler #2 - installed in 1967) it would not be practical to provide these boilers with the latest state-of-the-art improvements, thus incurring a large expense for a limited extension of the life time of these boilers. Rather, the improvement expenditures should be limited to those which can be recouped in a fairly short period of time, say 2 to 5 years.

Since the flue gas outlet temperature of Boiler #1 is high (330°C at full load), a feedwater economizer section can be added to lower the flue gas outlet temperature to 175°C

Le présent rapport considère les économies d'énergies potentielles pour deux chaudières existantes à l'usine de Canbra Food Ltd. à Lethbridge, Alberta. L'efficacité de chaque chaudières est étudiée ainsi que les différentes améliorations possibles pour accroître le rendement.

Les conclusions de l'étude sont resumées comme suit:

Etant donné que les deux chaudières sont anciennes (la chaudière No. 1 fût installée en 1959 et la chaudière No. 2 en 1967), équiper ces installations avec les techniques de pointe entraînenait des dépenses sans rapport avec les gains réalisables pendant une courte période.

Seules les améliorations permettant un retour d'investissement de l'ordre de 2 à 5 ans devraient être considérées.

Etant donné la haute température des gaz à la sortie de la chaudières No. 1 (330°C à plein régime), un circuit pourrait être ajouter pour réduire la tempéra-

(approximately 50°C above the dew-point) and preheat the feedwater to the boiler. Depending on the economiser installed, this modification would increase the overall operating efficiency by some 7.3% and should pay out in 2 to 3½ years.

The combustion control system for Boiler #1 can be updated to include an oxygen analyzer to trim the O_2 levels, and hence the air/fuel ratio, over a wider range of boiler operation. The control system is presently set with a considerable excess air "cushion". This modification could increase the overall efficiency by some 1.5% and should payout in the order of 3 to 4 years.

Both the forced draft and induced draft fan motors appear to be oversized. The motor size in both cases could be reduced by approximately 30%.

ture de sortie des gaz à 175°C (environ 50°C au dessus du point de rosée) et réchauffer l'arrivée d'eau. En fonction du système employé, cette modification améliorerait l'éfficacité générale par environ 7.3% et serait rentable entre 2 et 3½ ans.

Le système de contrôle de la combustion pour la chaudière No. 1 pourrait être amélioré pour comprendre un réglage automatique du taux d'oxygène afin de réduire le niveau d'émission d'O_2. Ceci permettrait un réglage du taux air/combustible pour différents taux d'utilization. Actuellement le système fournit un excès important d'air. Cette amélioration pourrait accroître l'éfficacité par environ 1.5% et serait rentable entre 3 et 4 ans.

Les ventilateurs d'air forcé et d'air induit sont équipés de moteurs sur-dimensionnés - la puissance de ces moteurs pourrait être réduite par environ 30%.

The combustion control system for Boiler #2 could be modified with O_2 trim in the same way as described for Boiler #1 to give better control of excess air over the complete range of boiler operation.

During the testing stage it was determined that the air preheater was leaking. The extent of the leakage was not determined, however, this condition should be remedied and the air preheater tubes cleaned.

In additiou, the following observations are made but no action is recommended at this time;

There is no natural gas metering system to either boiler and the valving and instrumentation on the gas lines to each boiler is less than optimum. For accounting and safety purposes these lines should be rearranged as shown on our Sketch in Appendix 7.

Le système de contrôle de combustion pour la chaudière No. 2 pourrait être équipé du système décrit pour la chaudière No. 1 pour couvrir une plus grande plage de fonctionnement.

Les tests ont demontré l'existence d'une fuite dans le système de pré-chauffage d'air. L'importance de cette fuite n'a pas été définie, quoi qu'il en soit, cette fuite devrait être réparée et les tubes de système nettoyés.

Les observations qui suivent sont à notées mais ne nécessitent pas une action à court terme:

Aucunne des deux chaudières n'est équipée d'un système de mesure du gaz naturel et les contrôles sur les conduites laissent à désirer. Pour des raisons de comptabilité et de sécurité, ces conduites devraient être modifiées comme indiquée sur la figure de l'appendice 7.

The common feedwater line to the boiler system appears to be undersized, since the pressure drop through this line when both boilers are firing in the upper load ranges is excessive. Consideration should be given to increasing the line size to reduce full load pumping power requirements and to enhance feedwater pressure control.

The report also examines projected costs of implementing the recommended modifications and monitoring the subsequent performance.

La conduite d'amenée d'eau commune aux deux chaudières semble sous-dimensionnée en considération des chutes de pressions excessives lorsque les chaudières marchent à plein régime. Afin de diminuer l'effort sur les pompes et d'améliorer le contrôle du système d'amenée d'eau, ie pourrait être souhaitable d'augmenter la taille de ces conduites.

Le rapport examine aussi les coûts projetés pour réaliser les différentes modifications suggérées et pour l'enregistrement des nouvelles performances.

1.0 INTRODUCTION

In February, 1984, Monenco Limited was engaged by Supply and Services Canada to conduct an evaluation program at the Canbra Foods Ltd. plant at Lethbridge, Alberta to determine areas of potential energy savings for the existing process steam boilers located within the plant.

The parameters reviewed included the fuel quality, consumption, boiler operation and loading, amount of excess air fired, controls, and the basic condition of the existing equipment.

From these observations the boiler combustion efficiencies are calculated and potential areas of improvement identified and evaluated.

2.0 CONCLUSIONS

The following basic conclusions can be drawn from the above tests and calculations.

.1 It is estimated that Boiler #1's overall operating efficiency can be increased by the order of 7.3% by the addition of a feedwater heater/economizer to recover heat from the flue gas. This addition yields both a rapid payout and a substantial saving in natural gas.

.2 A further efficiency increase for Boiler #1 of some 1.5% can be expected by the addition of O_2 trim to the boiler controls to reduce the amount of excess combustion air.

.3 No substantial efficiency increases can be realized for Boiler #2, although an O_2 trim system would probably result in an increase in efficiency of some 0.3%.

.4 No changes are recommended to the burners for either of the two boilers as no substantial gains can apparently be achieved (see correspondence with manufacturer).

3.0 BOILER EFFICIENCY TEST PROCEDURE

The complete Boiler Efficiency Test Procedure is included in Appendix 2. The efficiency test was conducted on a Heat Loss basis with the extent of the losses being evaluated by type and amount. From test results, the loss data were computed in accordance with the "Combustion Handbook for Canadian Fuels, 1973 - Volume 2/Gaseous Fuels". The results of these calculations are shown in Section 4.5 of this report.

4.0 BOILER EFFICIENCY TEST

4.1 GENERAL

A boiler efficiency test was performed in accordance with the test procedure detailed in Appendix 2 on both Boiler #1 and Boiler #2 at the Canbra Foods plant in Lethbridge, Alberta on March 21 and 22, 1984.

For the test period on each boiler, one boiler was set in the automatic firing mode and the other manually adjusted to the desired test loads. The boiler under test was allowed to stabilize for approximately 15 minutes before commencing the test readings. The loads on the boiler under test were varied from full load down to approximately 35% of full load. Lower loads were not able to be achieved due to the total steam demand from the process.

A copy of the flow recording charts for each boiler are included under Appendix 4 for reference.

4.2 TEST EQUIPMENT

The equipment used to take the main test readings was generally the existing plant instrumentation which had been previously calibrated.

Steam flow, pressure and temperature were read from the local plant instrumentation board, calibrated in April, 1983; the combustion air temperature was read local to the forced draft fan intake by a calibrated thermometer labelled ASTM 36 B 56350 by ERTCO; and the stack

gas temperature was measured by a point contact pyrometer No. KM 450, calibrated the day of the test in the laboratory at Canbra Foods.

The O_2 content of the flue gases was measured by a Bacharach Fyrite Test Kit No. 10-5011 obtained from Wirtanen Electric Co., Edmonton.

A copy of the Instruction Manual for the Bacharach Fyrite combustion gas analyzer is included under Appendix 8 for reference.

4.3 TEST RESULTS

The following measurements were taken over a period of time as indicated on the attached flow charts included under Appendix 4.

As the plant instruments are in Imperial units, readings taken on these instruments have been shown in Imperial units with the SI conversion shown in brackets. Where readings were taken in SI units, no imperial conversion is shown. Also, where data from outside sources were obtained in Imperial units, these are shown in Imperial units with the SI conversion in brackets.

The calculations are generally based on SI units with Imperial unit conversions shown in brackets where required for clarity.

Tables 4.1 and 4.2 summarize the test data taken.

4.4 FUEL DATA

The following are the volumetric analysis and ultimate analysis of the natural gas delivered in the North Lethbridge area for the period March 21/22, 1984:

	Volumetric Analysis, Percent by volume	Ultimate Analysis, as received Percent by weight
Nitrogen	1.42	2.31
Methane	91.17	84.24
Carbon Dioxide	0.39	0.98
Ethane	4.35	7.56
Propane	1.11	2.83
Butane	0.39	1.33
Pentane	0.10	0.40
Hexane Plus	0.06	0.35
	100.00	100.00

Higher Heating Value: 1044 Btu/cu ft at 60°F/14.65 psia dry basis (38 890 kJ/m^3 at 15.5°C/101 kPa (abs) dry basis)

Relative density: 0.608

The above analysis was obtained from Canadian Western Natural Gas Co., Calgary.

The Combustion Data graphs used in this calculation were computed by Energy, Mines and Resources Canada, to conform to the above values (Appendix 3).

4.5 CALCULATION RESULTS

451 BOILER EFFICIENCY

Assuming that the percentage of CO in the flue gas is zero at all loads (CO level was not measured), Table 4.3 and 4.4 detail the heat losses and boiler efficiencies as calculated from the Combustion data graphs attached as Appendix 3.

Both boilers were tested over a range of approximately 35% to 100% loading conditions. The efficiencies obtained remained essentially constant over this range and can be summarized as Boiler #1 - 75% and Boiler #2 - 84%.

452 FAN CAPACITY

A check calculation was made using the combustion data graphs in Appendix 3 to confirm the fan sizing on both units at full load as noted below:

.1 Boiler #1

Heat release (to steam)	= 30.84 x 10^6 Btu/hr (full load) (9036 kJ/s)
Combustion efficiency	= 75.5%
Flue gas temperature	= 631°F (333°C)
Excess air	= 28%
Natural gas heating value	= 1044 Btu/cu ft (38 890 kJ/m^3)
Combustion air temperature	= 30.7°C
Required fuel input	= $\frac{9036}{0.755}$
	= 11968 kJ/s

(a) Forced Draft Fan Performance

- From Fig. 1 at 128% total air, flow of dry air = 20.7 kg/kg of fuel.

- From Fig. 2, at a combustion air temperature of 30.7°C and 128% total air, the volume of dry air at 29.92"Hg = 17.5m^3/kg of fuel.

Density of fuel = 0.7433 kg/m^3 (based on relative density of 0.608)

Heating value = 38890 kJ/m^3

$$= \frac{38890}{0.7433}$$

= 52320 kJ/kg

Fuel use

$$= \frac{11968}{52320}$$

= 0.2287 kg/s

Required volmetric flow of air of F.D. fan = 17.5 x 0.2287 m^3/s + margin

= 4.00 m^3/s + margin

From Fig. 6 correction factor at 914 m (2999 ft) above sea level at 80°F (26.7°C) = 1.118

Therefore required actual volumetric flow = 1.118 x 4.00

= 4.47 m^3/s + margin

Assuming 20% margin = 4.47 x 1.2

= 5.36 m^3/s actual (11,378 acfm)

Fan test block head = 4.38 inches of water (ref. boiler data sheet Appendix 5)

Assumed efficiency = 80%

Power required = $\frac{11,378 \times 4.38}{6356 \times 0.8}$

= 9.8 HP (7.3 kW)

Motor HP supplied = 15 HP (11.2 kW)

Motor is 53% oversized.

(b) Induced Draft Fan Performance

- from Fig. 1 at 128% total air, flow of total flue gas = 21.8 kg/kg of fuel.

- from Fig. 2 at 128% total air and 333°C, the volume of flue gas = 37 m^3/kg of fuel.

Required volumetric flow of air of ID fan = 37 x 0.2287

= 8.46 m^3/s + margin

- From Fig. 6, correction factor at 914 m (2999 ft) above sea level at 26.7°C = 1.118

Therefore required actual volumetric flow = 1.118 x 8.46

= 9.46 m^3/s + margin

Assuming 20% margin = 9.46 x 1.2

= 11.35 m^3/s actual (24,057 acfm)

Fan test block head = 5.58 inches of water (see Appendix 5)

Assumed efficiency = 70%

HP required = $\frac{24,057 \times 5.58}{6356 \times 0.7}$

= 30.2 HP (22.5 kW)

Motor HP supplied = 40 HP (29.8 kW)

Motor is 32% oversized

.2 Boiler #2

Heat released (to steam)	= 41.12 x 10^6 Btu/hr (full load) (12048 kJ/s)
Combustion efficiency	= 83.9%
Excess air	= 8.5%
Natural gas heating value	= 1044 Btu/cu ft (38890 kJ/m^3)
Combustion air temperature	= 38.7°C
Required fuel input	= $\frac{12048}{0.839}$
	= 14360 kJ/s

(a) Forced Draft Fan Performance

- From Fig. 1, at 108.5% total air, flow of dry air = 16.9 kg/kg fuel.

- From Fig. 2, at combustion air temperature of 38.7°C and 108.5% total air, volume of dry air at 29.92" Hg = 15.5 m^3/kg.

Fuel use	= $\frac{14360}{52320}$
	= 0.274 kg/s
Required volumetric flow of air of FD fan	= 15.5 x 0.274 m^3/hr
	= 4.25 m^3/s + margin

- From Fig. 6, correction factor at 914 m (2999 ft) above sea level at 80°F (26.7°C) = 1.118

Therefore required actual volumetric flow	= 1.118 x 4.25
	= 4.74 m^3/s

Assume 20% margin	= 1.2 x 4.75
	= 5.70 m^3/s (12,088 acfm)
Fan Test Block end	= 15.0 inches of water (ref. Appendix 5)
Assumed efficiency	= 80%
HP required	= $\frac{12,088 \times 15.0}{6356 \times 0.8}$
	= 35.7 HP (26.6 kW)
Motor HP supplied	= 40 HP (29.8 kW)
Motor is 12% oversized	

.3 Summary

The above calculated fan power requirements, although only approximately since the operating efficiencies are not known with certainty, indicate that both the FD and ID fan motors on Boiler #1 are oversized. This is probably due to the fact that this boiler was originally sized to fire sunflower husks with a Dutch oven, thus the quantity of air required, and hence flue gases produced, was greater than that now required.

The calculation also indicates that the FD fan motor on Boiler #2 appears to be correctly sized.

TABLE 4.1

Boiler #1: Rated 30,000 lb/hr: 150 psig/D.S.* (3.78 kg/s: 1034 kPa (ga))
Date: March 21, 1984
Time: 12:00 p.m. to 4:30 p.m.

Steam Flow	lbs/hr (kg/s)	30,000 (3.78)	25,000 (3.15)	22,000 (2.77)	15,000 (1.89)	11,200 (1.41)
% Full Load	%	100	83.3	73.3	50	37.3
Steam Pressure	psig (kPa(ga))	158 (1089)	158 (1089)	156 (1076)	153 (1055)	151 (1041)
Comb. Air Temp.	°C	30.7	34.6	34.6	34.6	34.6
Stack Flue Gas Temperature	°F (°C)	630 (333)	580 (304)	570 (298)	525 (274)	500 (260)
O_2 in Flue Gas	%	5	6.5	7.5	8.7	9.7

* Dry, saturated

TABLE 4.2

Boiler #2: Rated 40,000 lbs/hr: 150 psig/D.S.*(5.04 kg/s: 1034 kPa (ga))
Date: March 22, 1984
Time: 11:00 a.m. to 1:30 p.m.

Steam Flow	lbs/hr (kg/s)	40,000 (5.04)	34,900 (4.40)	29,700 (3.74)	21,000 (2.65)	15,000 (1.89)
% Full Load	%	100	87.3	74.3	52.5	37.5
Steam Pressure	psig (kPa(ga))	169 (1165)	154 (1062)	159 (1096)	154 (1062)	146 (1007)
Comb. Air Temp.	°C	38.7	39.6	38.8	38.4	39
Stack Flue Gas Temperature	°F (°C)	408 (209)	390 (199)	350 (177)	310 (154)	280 (138)
O_2 in Flue Gas	%	1.75	2.25	3	3.5	4.9

* Dry, saturated

TABLE 4.3

.1 Boiler #1

Steam Flow	lbs/hr (kg/s)	30,000 (3.78)	25,000 (3.15)	22,000 (2.77)	15,000 (1.89)	11,200 (1.41)
Boiler Load	%	100	83.3	73.3	50	37.3
Heat Output	Btu/hr (kJ/s)	30.84×10^6 (9036)	25.7×10^6 (7530)	22.6×10^6 (622)	15.4×10^6 (4512)	11.5×10^6 (3370)
O_2 Content	%	5	6.5	7.5	8.7	9.7
Excess Air	%	28	40	45	63	77
Heat Losses:						
a) Dry Flue Gas Loss	%	12.0	11.5	12.0	11.9	12.0
b) Hydrogen Loss	%	11.35	11.1	11.05	10.85	10.7
c) CO Loss		0.0	0.0	0.0	0.0	0.0
d) Unmeasured Loss	%	0.25	0.25	0.25	0.25	0.25
e) Radiation and Convection Loss	%	0.85	1.0	1.2	1.8	2.2
f) Total losses	%	24.45	23.85	24.50	24.80	25.15
Efficiency (100 - losses)	%	75.55	76.15	75.5	75.2	74.85

TABLE 4.4

.2 Boiler #2

Steam Flow	lbs/hr (kg/s)	40,000 (5.04)	34,900 (4.40)	29,700 (3.74)	21,000 (2.65)	11,200 (1.89)
Boiler Load	%	100	87.25	74.25	52.5	37.5
Heat Output	Btu/hr (kJ/s)	41.12×10^6 (12048)	35.88×10^6 (10513)	30.53×10^6 (8945)	21.59×10^6 (6326)	15.42×10^6 (4518)
O_2 Content	%	1.75	2.25	3	3.5	4.9
Excess Air	%	8.5	11.5	15	18	28
Heat Losses:						
a) Dry Flue Gas Loss	%	5.2	5.0	4.7	4.0	3.9
b) Hydrogen Loss	%	10.3	10.2	10.1	9.9	9.75
c) CO Loss	%	0.0	0.0	0.0	0.0	0.0
d) Unmeasured Loss	%	0.25	0.25	0.25	0.25	0.25
e) Radiation & Convection Loss	%	0.75	0.9	1.0	1.2	1.9
f) Total losses	%	16.50	16.35	16.05	15.35	15.80
Efficiency (100 - losses)	%	83.5	83.65	83.95	84.65	84.2

5.0 AREAS WHERE UPGRADING MAY BE CONSIDERED

5.1 GENERAL

This section identifies several areas where the operation, and in particular the efficiency, of the existing boilers can be improved.

Pending confirmation by Canbra Foods of the actual average boiler loading, all cost benefit analyses are conservatively based on the boilers operating at 2/3 (67%) of their rated capacity for essentially 100 percent of the operating time. This loading was selected based on the yearly figures noted in Appendix 10, and on the loading charts included in Appendix 4.

5.2 FEEDHEATER/ECONOMIZER ON BOILER #1

521 EFFICIENCY INCREASE

Reducing the stack flue gas temperature on Boiler #1 will reduce both the dry flue gas losses and the loss due to moisture in the flue gas formed from the combustion of hydrogen.

Reducing the stack flue gas temperature to 175°C (347°F) from the present 67% load stack temperature condition of 292°C (558°F), will result in the following increase in efficiency (using the Combustion Data Graphs in Appendix 3) for 67% boiler loading.

(i) Dry flue gas loss at 152% total air and a temperature differential of (175-34.6) = 140.4°C is 5.3%.

(ii) Hydrogen loss at stack temperature of 175°C and combustion air temperature of 34.6°C is 10.1%.

(iii) Thus total losses at 175°C are (5.3 + 10.1) = 15.4%.

(iv) Compared to the present total losses of (12.0 + 10.7) = 22.7% at 67% load conditions, the economizer will increase the efficiency of the unit by approximately (22.7 - 15.4) = 7.3% at 67% load.

For the purpose of comparison, using a heat exchanger sized to produce the above conditions, the following associated potential efficiency increases were calcualted at the indicated loadings: a) 100% load, + 5.2% and, b) 50% load, + 7.0%. These calculations allowed the flue gas (stack) temperature to vary as permitted by the heat exchange capacity of the proposed economizer (i.e., no flue gas temperature control is included). These figures indicate a relatively constant efficiency increase over the selected boiler leading range.

522 COST BENEFIT

As calculated in 521, the efficiency of Boiler #1 can be conservatively increased by 7.3% at two thirds load for an overall efficiency of 83.0%. The following calculations demonstrate the potential cost saving of this efficiency increase.

.1 Estimate Gas Cost

Estimate monthly natural gas cost using Rate N°3 of Rate Schedule "A" (see Appendix 9)

(i) Calculate Billing Demand Change:

Maximum 12 hr fuel usage for boilers =

$$\frac{(\text{fuel consumption, kJ/s, Boiler\#1} + \text{fuel consumption, kJ/s, Boiler\#2})\ (60)(60)(12)}{10^6}$$

$$= \frac{(11960 + 14306)\ (60)(60)(12)}{10^6}$$

= 1137 GJ

Boilers account for 75% of plant demand (see Appendix 10) therefore total plant demand = $\frac{1137}{0.75}$

= 1516 GJ in 12 hours

Monthly demand cost @ \$5.25/GJ = (1516) (5.25)

= \$7959/month

Plus fixed charge: = 125/month

Total fixed charge: \$8084/month

(ii) Calculate Energy Charge:

(a) Yearly demand (1982) by boilers = 377327 GJ.

(b) Current monthly energy charge (May, 1984) is (1.1111) (2.130) = \$2.367/GJ based on High Load Factor Rate #3 (See Appendix 9)

(c) Total energy charge per month = $\frac{377327}{12}$ x 2·367

= \$74428

.2 Calculate Cost Benefit

Proportion of energy charge due to Boiler #1:

$$= \frac{\text{(Capacity of Boiler \#1)}}{\text{(Capacity of Boiler \#1 + Capacity of Boiler \#2)}} \times (\$/\text{month})$$

$$= \frac{(30)}{(70)} (74428)$$

= $31898/month

Assume that the efficiency saving will not alter the Demand Charge and that all savings come out of the Energy Charge only:

Then, a 7.3% increase in Boiler #1 efficiency will yield a saving of (0.073) (31898) = $2329 per month, say $2300 per month.

Based on the similar efficiency changes at other boiler loadings noted in 521, the actual savings will be basically in direct proportion to the actual boiler loading experienced.

523 FLUE GAS ECONOMIZER COST

.1 Babcock & Wilcox Proposal

Babcock and Wilcox in their letter of April 27, 1984, (see Appendix 6) agree that a stack mounted feedwater heater/economizer unit can be added to Boiler #1. They estimate the equipment cost at $40,000 and the installation cost at another $30,000 for a total of $70,000 direct costs, installed. Adding 40% for indirect costs, engineering, and contingencies results in a total installed cost of $100000.

At $2300/month saving, this would payout in the order of some 39 months.

The sketches in Appendix 6 show that this unit would be installed in the existing stack, downstream of the ID Fan.

.2 KeepRite Unifin Proposal

KeepRite Unifin have proposed a duct mounted economizer for an equipment cost of some $5300 (see Appendix 6). If the installation and overhead costs remain roughly the same as the B&W proposal in 523.1, the total installed cost for this Unit would be in the order of $66000. This would yield a payout period of some 24 months.

The sketches in Appendix 6 indicate the area of existing boiler ductwork in which this unit could be installed upstream of the ID fan.

As the ID fan is presently oversized in any case, it will be able to handle the additional pressure drop caused by either of the above feedheater/economizer configurations.

5.3 COMBUSTION AND CONTROL SYSTEMS

531 GENERAL

The following areas of the boiler control systems could be improved to provide better boiler efficiency and load following characteristics:

(i) Add O_2 trim control to improve the combustion control system's air/fuel ratio and hence the boiler efficiency. In doing so the combustion control should be changed to cross-over limiting. Additional instrumentation will be required to measure the air and gas flows.

(ii) Replace the present pneumatic control with more up-to-date solid state/microprocessor based controllers. This will improve the control response and avoid any efficiency loss due to out of tune controls. At the moment, the control response of Boiler #2 is particularly sluggish.

(iii) Apply steam flow feed forward to improve the steam header pressure control. During the efficinecy test it was found that the plant header pressure control was poor and the header pressure varied from 150 psig to more tha 170 psig causing the safety valve to blow. Plant efficiency will be increased if overpressure can be avoided.

(iv) Replace the present feedwater control system and increase the capacity of the feedwater piping system. Two element or three element feedwater control could be considered if rapid load transients are to be expected in the future.

(v) Automate the boiler blowdown with an on-line analyzer. This will increase the boiler efficiency as presently the boiler blowdown is continuous.

(vi) Optimize the loading of the two boilers. This can save fuel costs in the order of 0.5-2.0% compared to the existing system of basically equal load sharing.

532 COST BENEFITS

.1 Boiler #1 O_2 Trim

Adding an O_2 trim control to Boiler #1 would help to reduce the excess air supplied to the boiler, particularly during turn down opera-

tion. For example, at the designated operating point of two thirds load, a reduction in total air from 158% to 120% (the design point) would yield an efficiency increase of some 1.5%, equivalent to a monthly fuel saving of the order of $500. This saving would payoff a $20000 installation cost in 40 months.

.2 Boiler #2 O_2 Trim

Adding the same system to Boiler #2 would result in an efficiency increase of only some 0.3% with reduction in excess air to 110% at two thirds load and hence is difficult to justify on cost payback alone.

.3 Optimized Loading (of both boilers)

Cost savings can be realized with the present boilers by optimizing the loading such that the more efficient Boiler #2 operates at full load as much as possible, while Boiler #1 follows the process demand fluctuations.

This type of loading can increase the overall boiler plant efficiency by up to 2% and hence provide monthly final savings of up to $1400.00.

With the addition of an economizer to Boiler #1, and hence an increase in this unit's efficiency, this type of loading would not provide any appreciable gain.

.4 Other Control Scheme Changes

None of the other control scheme changes noted in Section 531 will provide any significant definable cost benefits to the specific operation of the boilers but they will provide a far smoother operating

response from the boiler plant. These could be further evaluted after the main recommendations have been incorporated.

5.4 OTHER CONSIDERATIONS

In addition to adding an economizer and/or an improved control scheme, the following additional points should also be considered as potential energy savers although the cost benefits of each are difficult to determine:

a) Repair of the firebrick at the bottom of Boiler #1 which appeared to be in poor condition. This work would reduce air leakage into the boiler, improve the eccess xir control, and reduce radiant heat losses.

b) Upgrade the external boiler insulation on both units to reduce radiant heat losses.

c) Repair the air heater on Boiler #2 which was determined, during the boiler testing, to be leaking.

d) Review the existing feedwater piping to determine whether or not there is an economical way to reduce existing high pressure drop which is presently limiting full load water delivery to the boilers. A reduction in head losses would improve the overall control of the boiler feedwater supply to the boilers.

5.5 SUGGESTED PLAN

551 STAGE I

Stage I involves a plan of approach to implementing and monitoring any modifications to the existing boilers at Canbra Foods. This plan covers only the addition of an economizer to Boiler #1 and the addition of O_2 trim to both Boilers #1 and #2.

This plan would include the following steps, an overall schedule for which is shown in Chart 5.1

a) Conduct a detailed inspection of each boiler (by the original manufacturer if possible) to determine their overall soundness, with specific attention being paid to the flue gas system and refractory work for Boiler #1.

b) Conduct a detailed review of the existing ductwork and structure around Boiler #1 to determine the desired location of new economizer.

c) Set the design parameters for the economizer.

d) Design the required modifications to the boiler feed piping and control system. This design should also consider an overall upgrading of the existing boiler feedwater system to reduce overall head losses on the system and to improve the degree of control.

e) Design and specify the required O_2 trim systems for both Boilers #1 and #2.

f) Obtain quotations for both the supply and installation of the economizer, and O_2 trim control systems. These could be either single or separate contracts.

g) Schedule the work to coincide as much as possible with scheduled boiler shutdowns and/or periods of low process steam demand and make the required modifications.

It is estimated that this work could be perfqrmed by an engineering consultant for a cost of the order of $20000.

552 STAGE II

Stage II involves the actual installation and commissioning of the new economizer, and O_2 trim systems. The total cost for this work is of the order of $106000 to $140000 as determined elsewhere in this report.

553 STAGE III

Stage III involves the monitoring and maintenance of the new systems for a nine (9) month period.

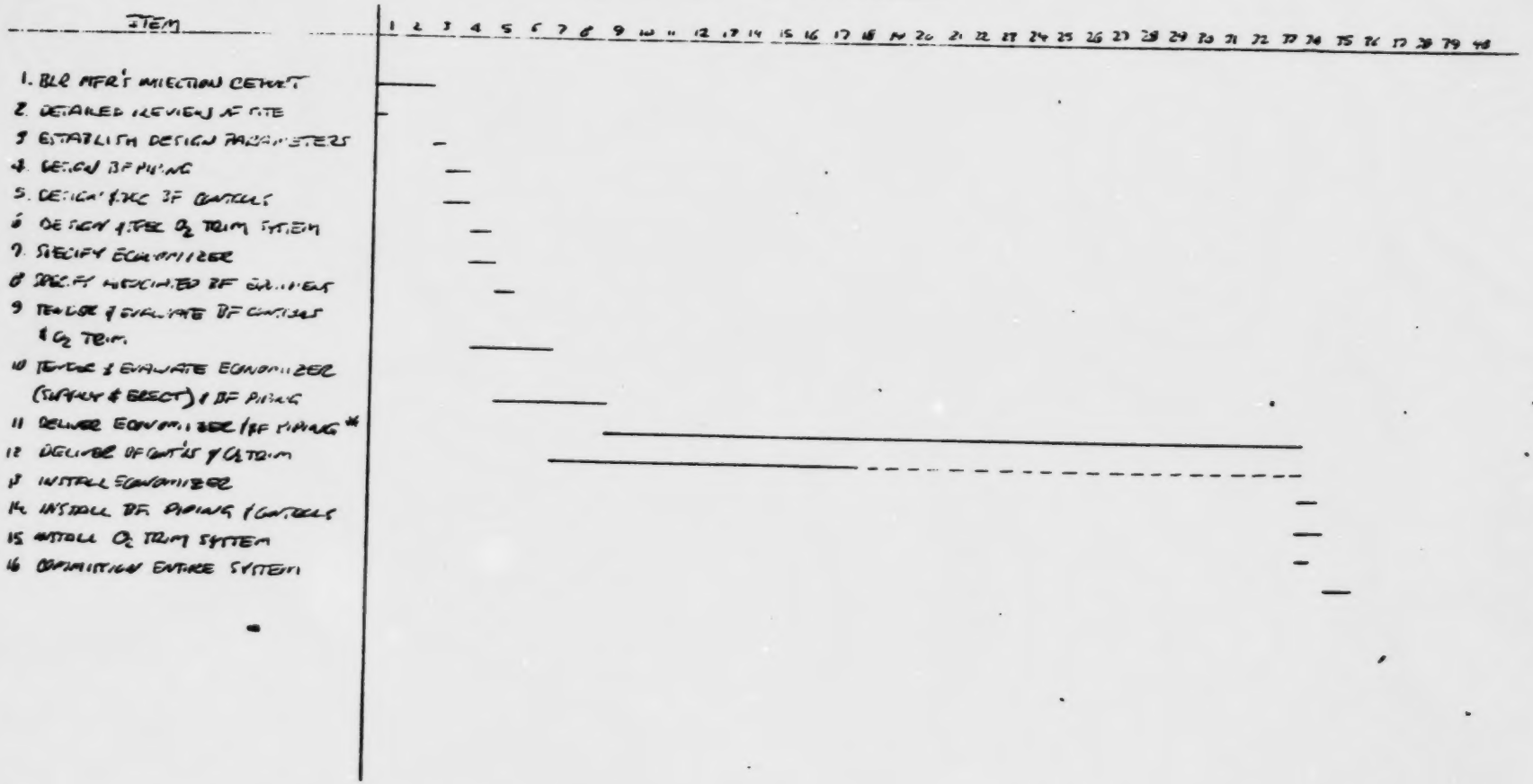
This work would be carried out primarily by the Canbra plant staff based on guidelines and requirements provided by the original engineer/designer. The engineer/designer would be at the plant during the initial commissioning of the systems and would visit thereafter, probably on a monthly schedule, to review the operation of the systems.

He would also review the daily operating data received and develop reports (monthly) on the operation of the new systems and compare both the fuel consumption and operational experience to past records and experience.

This work could be performed for the order of $10,000.

CHART 5.1

ESTIMATED ENGINEERING / CONSTRUCTION SCHEDULE


ITEM
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 35 36 37 38 39 40
1. BLR MFR'S INJECTION CERTIFT
2. DETAILED REVIEW AT SITE
3 ESTABLISH DESIGN PARAMETERS
4. DESIGN BF PIPING
5. DESIGN/REC BF CONTROLS
6 DESIGN/SPEC O_2 TRIM SYSTEM
7. SPECIFY ECONOMIZER
8 SPEC/PURCHASE BF EQUIPMENT
9 TEST OR EVALUATE BF CONTROLS & O_2 TRIM
10 TEST OR EVALUATE ECONOMIZER (SUPPLY & ERECT) & BF PIPING
11 DELIVER ECONOMIZER/BF PIPING *
12 DELIVER BF CONTS & O_2 TRIM
13 INSTALL ECONOMIZER
14 INSTALL BF PIPING/CONTROLS
15 INSTALL O_2 TRIM SYSTEM
16 COMMISSION ENTIRE SYSTEM

* BASED ON 3/W ESTIMATED DELIVERY

APPENDIX 1

CORRESPONDENCE

CANBRA FOODS LTD / P.O. BOX 99 LETHBRIDGE ALBERTA CANADA T1J 3Y4 / TELEPHONE (403) 327-5781 / TELEX 038-[illegible]

RECEIVED
THERMAL DIVISION
JUN 22 1984
File No. D55-8075-3

June 20, 1984

Mr. John Harding
Monenco Consultants Ltd.
400 Monenco Place
801 - 6th Avenue S.W.
Calgary, Alberta
T2P 3W3

Dear Mr. Harding;

Attached please find the information you have requested.

Please note that we do not have a seperate gas meter for the Boiler House. We, therefore, apply 75% of the gas consumption to the Boiler House and the other 25% is allotted elsewhere.

I trust this is satisfactory.

Yours truly,

Jody Owen
General Accounting Clerk

/jo

Natural Gas Consumption - Boiler House

20 June, 1984

	Gigajoules	x	75%
January	53694.50		40270.88
February	36402.52		27301.89
March	55686.34		41764.76
April	34389.65		25792.24
May	49067.51		36800.63
Total Year To Date	229240.52		171930.40

Steam Production - Boiler House (1000 Pounds)

	Month	Year To Date
January	31026	31026
February	31606	62632
March	36835	99467
April	24068	123535
May	31370	154905

Monenco

Monenco Limited
400 Monenco Place, 801 - 6th Avenue S W
Calgary, Alberta, Canada T2P 3W3
Tel (403) 298-4170
Telex 038-22636

24 February 1984

File: DSS 8075-3

Canbra Foods Ltd.
Box 99,
Lethbridge, Alberta

Attention: Mr. R. Kinnee,
Chief Engineer

Dear Sirs:

Subject: Enersolve Demonstration Project

Please find enclosed a copy of the minutes of our meeting at Canbra Foods Ltd., Lethbridge, Alberta on 16 February 1984.

Since our meeting, the Department of Supply and Services (DSS), Canada, has instructed us that they wish the boiler efficiency tests to be conducted according to the Heat Loss method, generally as described in their handbook "A Combustion Handbook for Canadian Fuels, Vol. 2 - Gaseous Fuels".

At our recent meeting, we had discussed the steps necessary to conduct the test according to the Input/Output method, whereby it was necessary to measure the natural gas flow and pressure to each boiler. By using the Heat Loss method this step is no longer necessary. Therefore, the changes to the natural gas lines are not required in order to conduct this test.

In order to conduct this test, the following information will be required:

1. Ultimate analysis and calorific value of the natural gas. (Can be obtained from Canadian Western Natural Gas Company).

2. The actual output rating of the boiler in BTU/hr. Since the test results will be to the tolerances normal in boiler room practice, we can use the Bailey flow meters installed on the units rather than install a more accurate measurement device as discussed under item (e) of the minutes.

.../2

3. The maximum continuous rating of the boiler.

4. Flue gas temperature in the stack. As discussed, we will use a point contact pyrometer in suitable connections in both stacks.

5. Combustion air temperature. Suitable temperature measurements of the boiler room temperature at the F.D. intakes should be available.

6. Analysis of the combustion flue gas. As discussed, we will provide a portable gas analyser.

As stated in the minutes, we will conduct this test in the latter half of March 1984.

Yours very truly,

J. Simpson

J. Simpson, P. Eng.

JS/ds
encl:
c.c. R.A. Bennett
J.R.C. Harding
D. Scoulding/D. Chan

MINUTES OF MEETING

DATE: 16 February 1984

FILE: DSS 8075-3

SUBJECT: Enersolve Program

PLACE: Canbra Foods Ltd., Lethbridge, Alberta

PRESENT:

Roy Sander	-	Canbra Foods
Ray Kinnie	-	Canbra Foods
Dan Chan	-	MECo
John Simpson	-	MECo

GENERAL

The two boilers in the central steam plant were reviewed. The data obtained was as follows:

Boiler #1
- Rated at 30,000 lb/hr/150 psig at 358°F (saturated steam)
- Type Babcock & Wilcox Type "GM"
- Balanced draft operation
- Purchased in 1958
- Designed for 20% excess air firing
- No economizer or air preheated
- Temperature of flue gases to stack was approx. 520°F.
- Burner arrangement was two gas rings burning natural gas with manual control.

Boiler #2
- Rated at 40,000 lbs/hr/150 psig at 358°F (saturated steam)
- Type Babcock & Wilcox Type "D"
- Pressurized furnace operation
- Purchased in 1967
- No economizer
- Tubular type air preheater included (AT = 266°F)
- Designed for 10% excess air firing
- Temperature of flue gases to stack = 354°F.
- Burner arrangement was a single circular gas multi-speed with manual control

The remaining boilers in the Canbra Foods plant consisted of three-off Dowtherm boilers used for heating #3 deodorizer to 500°F using natural gas as fuel. A review of these boilers (two vertical type and one horizontal type) showed that it would be impractical to incorporate any type of low excess air burner to improve the boiler efficiency.

.../2

The setting and refractory of both boilers was considered to be in good repair. In fact, the refractory on boiler #1 had been repaired and upgraded 3-4 years ago.

The water treatment (sodium zeolite water softening) of the boiler water was considered to have an excellent performance.

No. 1 boiler is a balanced draft unit and it appears that the induced draft fan is oversized since it was designed for drawing the gas from a Dutch oven. Some of the induced draft louvres have been sealed off. Motor size is 40 H.P. which could be reduced.

Natural gas flow measurement to each boiler was not available.

Air preheater on Unit #2 is a tubular type and appears to be leaking.

Burners on both boilers are on manual control only.

No control schematics or tubing diagrams were available.

BOILER EFFICIENCY TESTS

The test points for measurement and data acquisition required to conduct an efficiency and combustion test on the units were discussed and the following actions decided:

a) Fuel ultimate analysis - Canbra will obtain the data from Canadian Western Natural Gas.

b) Natural gas lines to the boilers - it was decided that the gas lines to each boiler did not allow sufficient space for the incorporation of reliable flow measurement devices. The gas lines will, therefore, be re-routed to allow for reliable measurement points to each boiler. A flow schematic of the revised gas lines with the required instrumentation for flow, temperature and pressure readings, and the necessary valving was submitted to Canbra. The physical re-routing of the gas lines was discussed and agreed on. Canbra will obtain a quote for materials and labour to re-route the gas lines. It is intended to perform this work before the end of February. Natural gas flow will be measured by a differential pressure indicator or a vortex meter.

c) Stack flue gas temperature: Canbra will use a point contact pyrometer and have suitable connections on both stacks available.

d) Steam pressure: Local steam pressure gauges will be used. Canbra will have these calibrated.

e) Steam flow: Canbra stated that the Bailey steam flow meters were suspect. It was decided that Canbra will install extra tees, valves and nipples on the sensing lines and Monenco will provide a differential pressure indicator for the test. Monenco will obtain the orifice data from Bailey Meter.

f) Oxygen content of flue gases: Monenco will rent a portable combustion gas analyser. Measurement points are available on both units from previous tests.

g) Feedwater flow measurement: Canbra indicated that the feedwater lines were undersized and any incorporation of flow measurement orifice plates could not be allowed. It was suggested that portable ultrasonic flow meters could be used. However, these may not be available locally. F.W. flow can be calculated from the steam flow if the boiler blowdown figures were available or could be shut-off for the duration of the test. This problem will be discussed further.

An approximate date was set for conducting the efficiency test on the boilers as the last quarter of March, 1984.

JS

JS/ds
c.c. D.O. Outhouse/J. Robinson
R.A. Bennett
D. Scoulding/D. Chan
J.R.C. Harding
Central Files

APPENDIX 2

BOILER EFFICIENCY TEST PROCEDURE

MONENCO LIMITED

ENERSOLVE DEMONSTRATION PROJECT

AT

CANBRA FOODS LTD., LETHBRIDGE

BOILER EFFICIENCY TEST PROCEDURE

1. GENERAL

The overall efficiency of the combustion system must first be measured in order to make recommendations for upgrading the system to improve the efficiency.

The efficiency test will be conducted on a Heat Loss basis and the extent of the losses evaluated by type and amount.

From the test results, the loss data will be computed from the combustion data graphs contained in the Combustion Handbook for Canadian Fuels, 1973 - Volume 2/Gaseous Fuels.

2. HEAT LOSSES TO BE MEASURED

The heat losses in the boiler system for gas-fired units can be listed as follows:

2.1 Heat loss due to the sensible heat in the dry flue gas leaving the boiler.

2.2 Heat loss due to the moisture in the flue gas formed from the combustion of the hydrogen content of the flue gas.

2.3 Heat loss due to the carbon monoxide in the flue gas resulting from incomplete combustion.

2.4 Heat loss due to unburned combustible.

2.5 Heat loss due to moisture in the combustion air.

2.6 Heat loss due to radiation and convection from the boiler.

All heat losses are measured in terms of the per cent of fuel input.

For gas-fired systems, the losses under items 2.4 and 2.5 above are usually very small and therefore an involved and accurate, method of measurement is not justified for this test. These losses will be summed together and represented as "unmeasured" losses. In most gas-fired systems, a reasonable value for "unmeasured" losses is 0.25% of fuel input.

The losses under item 2.6, loss due to radiation and convection will be approximated by using the radiation loss chart of the American Boiler Manufacturers Association (ABMA). For boilers operating at a full load output of greater than 20 x 10^6 BTU/hr (values in this case are 30-40 x 10^6 BTU/hr), the radiation and convection losses are estimated to be within an accuracy of within ± 0.5% of total heat input, by using this method.

The heat losses under items (2.1), (2.2), (2.3), can be determined by using the graphs in the Combustion Handbook previously mentioned.

3. INPUT VALUES REQUIRED

In order to calculate a heat balance according to the heat loss method, the following data are required:

3.1 Type and heating value of the natural gas, in BTU/cu.ft.

3.2 Maximum continuous output rating of the boiler, in BTU/hr.

3.3 Actual output of the boiler, in BTU/hr.

3.4 Stack flue gas temperature, in °F.

3.5 Combustion air temperature, in °F.

3.6 Flue gas analysis giving the O_2 and CO content in per cent by volume.

4. FUEL DATA

The boilers will be fired with natural gas. The following data on the natural gas-fired will be obtained from Canadian Western Natural Gas.

Calorific Value BTU/cu.ft. at 60°F/30" Hg.

Ultimate Analysis - % by weight

Carbon
Hydrogen
Sulphur
Nitrogen
Oxygen
Water
Ash

5. TEST PREPARATION

Before each test result is recorded, the following adjustments must be made:

- Manually adjust the air flow to each burner to give the minimum air flow required for good combustion and a stable flame.
- Allow the boiler to stabilize for at least 15 minutes before commencing the test readings in order that steady state conditions are reached.
- Ensure that the blowdown valves are closed prior to taking test results.

The following instrumentation should be calibrated to ensure that reliable results are obtained.

- o steam flow
- o steam pressure/temperature
- o combustion air temperature
- o stack flue gas temperature

6. TEST PROCEDURE

The following procedure should be used throughout the test at each constant load point:

6.1 With load constant, record the values mentioned previously and the steady state level of O_2.

6.2 Manually increase the load 10% above that in step 6.1 and record the steady state level of O_2.

6.3 Slowly bring the load back to that in step 6.1 and record the maximum, minimum and steady state levels of O_2.

6.4 Manually decrease the load 10% below that in step 6.1 and record the steady state O_2 level.

6.5 Slowly increase the load back to that in step 6.2 and again record the maximum, minimum and steady state levels of O_2.

6.6 Repeat the entire test for 100%, 75%, 50%, 25% load points.

The above readings will indicate the dynamic errors in the controls and transient conditions in the boiler. This in turn will provide information for selecting the necessary type of low excess air controls required for this boiler installation.

MONENCO LIMITED

BOILER EFFICIENCY TEST

COMPANY	:	Canbra Foods Ltd.
TYPE	:	Process Steam Generation
LOCATION	:	Lethbridge/Alberta
DATE	:	

BOILER DATA

BOILER NO.	ONE	TWO
BOILER MAKE	BABCOCK & WILCOX	BABCOCK & WILCOX
TYPE	TYPE GM	TYPE D
MAX. CAPACITY	30,000 LBS/HR.	40,000 LBS/HR.
STEAM PRESSURE	150 PSIG	150 PSIG
STEAM TEMPERATURE	DRY & SATURATED	DRY & SATURATED
DRAFT TYPE	BALANCED DRAFT	PRESSURIZED
AIR PREHEATER	NONE	TUBULAR
ECONOMIZER	NONE	NONE
BURNER TYPE	TWO-GAS RINGS	ONE-CYCLONE GAS MULTI-SPUD
FUEL	NATURAL GAS	NATURAL GAS
COMBUSTION CONTROL	BAILEY MINI-LINE	BAILEY MINI-LINE
EXCESS AIR	20%	10%
F.W. TEMP.	200°F	200°F

MONENCO LIMITED

BOILER TEST DATA

CANBRA FOODS LIMITED
LETHBRIDGE, ALBERTA

BOILER NO.

BLOWDOWN-ZERO

TEST NO.		1	2	3	4
DURATION	MINS				
FULL LOAD RATING	%	100	75	50	25
STEAM FLOW (AS READ)	LBS/HR				
STEAM PRESSURE (DRUM)	PSIG				
STEAM TEMP. (DRUM)	°F				
COMBUSTION AIR TEMP.	°F				
STACK FLUE GAS TEMPERATURE	°F				
O_2 IN FLUE GAS	% BY VOL.				
CO IN FLUE GAS	% BY VOL.				

Readings taken by

(Signature)

Date:

APPENDIX 3

COMBUSTION DATA GRAPHS

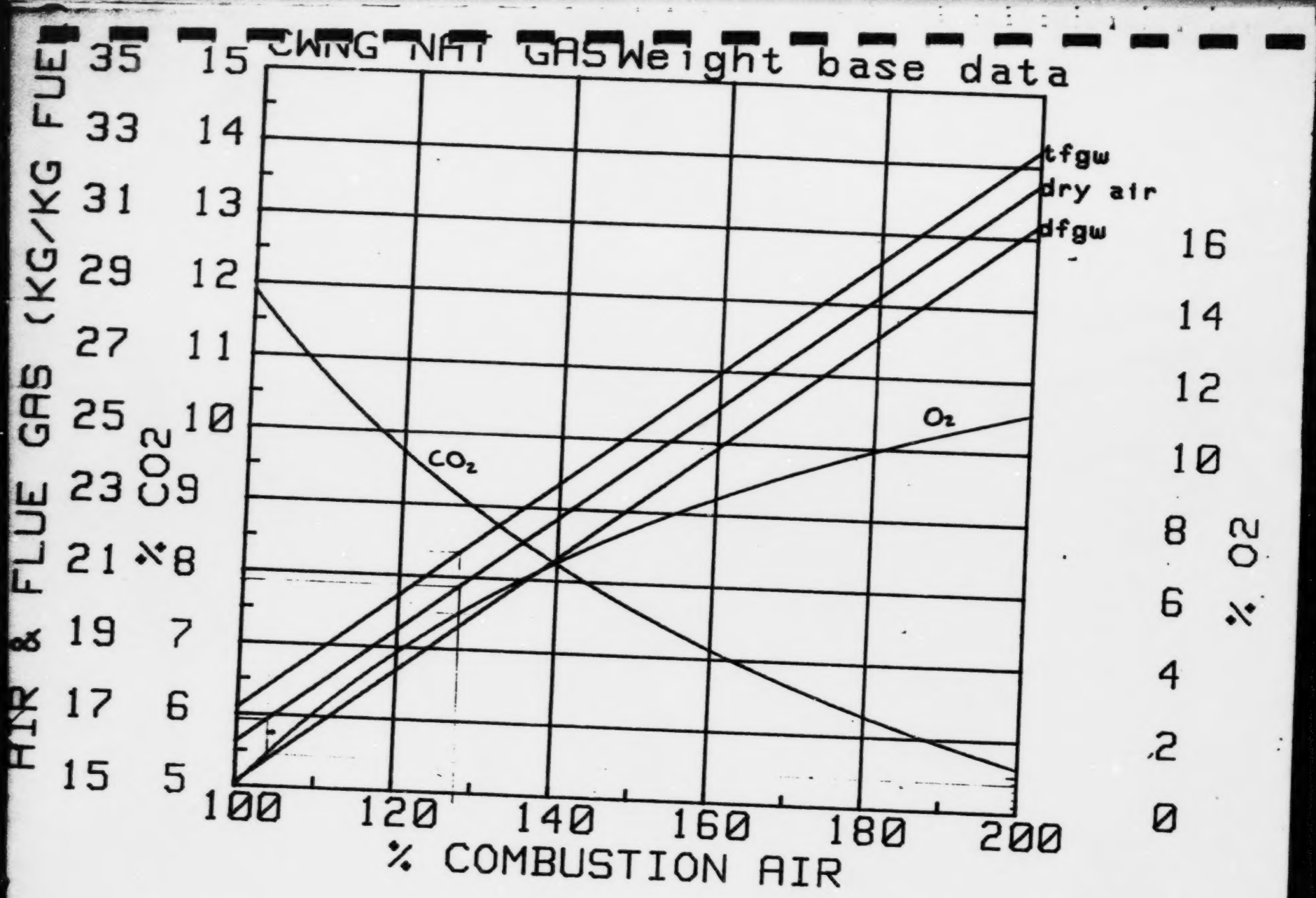

CWNG NAT GAS Weight base data
AIR & FLUE GAS (KG/KG FUEL)
% CO2
% O2
% COMBUSTION AIR
tfgw
dry air
dfgw
CO2
O2
35
33
31
29
27
25
23
21
19
17
15
15
14
13
12
11
10
9
8
7
6
5
16
14
12
10
8
6
4
2
0
100
120
140
160
180
200

Figure 1

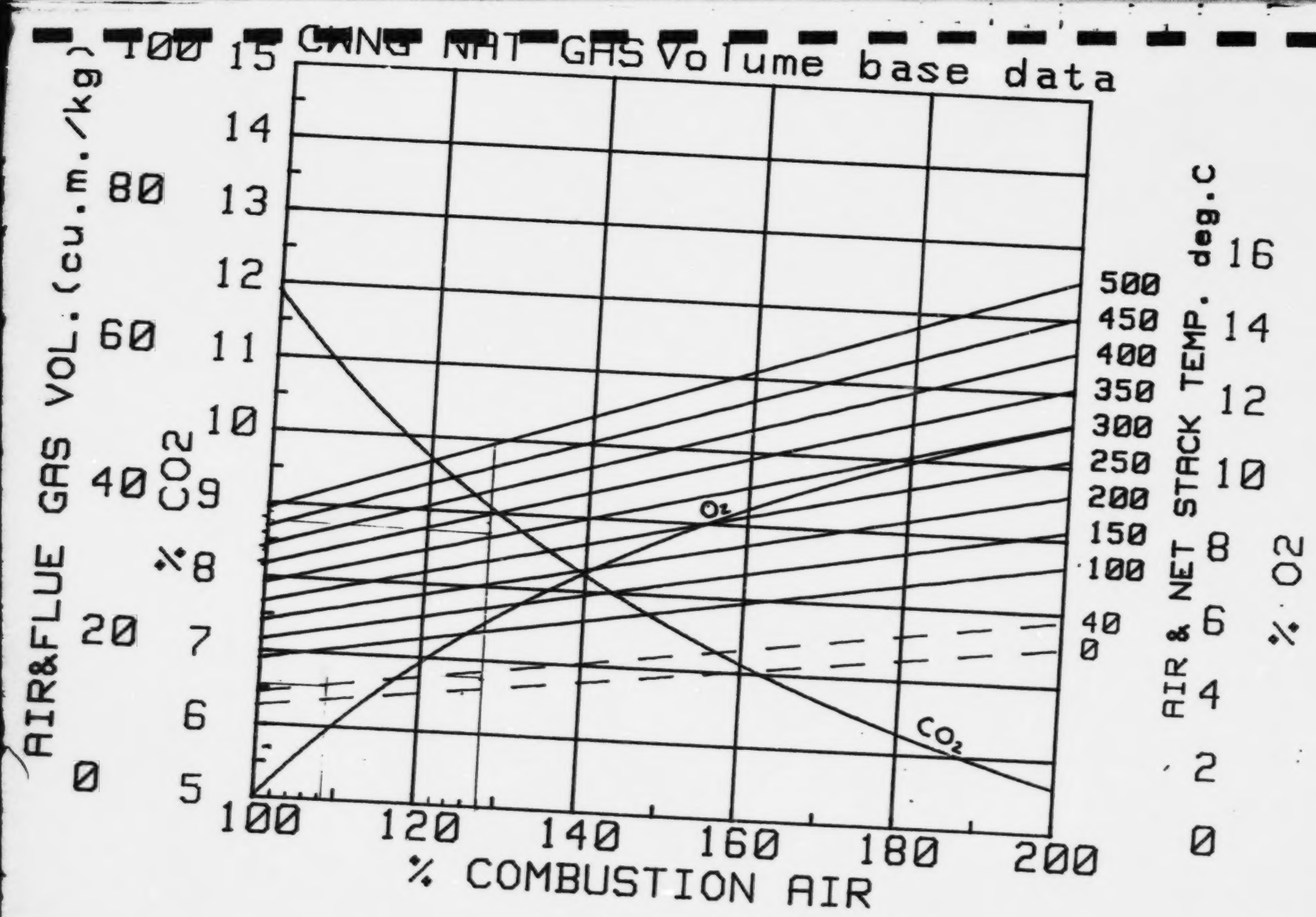

CNNG NAT GAS Volume base data
AIR&FLUE GAS VOL. (cu.m./kg)
100
80
60
40
20
0
15
14
13
12
11
10
9
8
7
6
5
% CO2
O2
CO2
100
120
140
160
180
200
% COMBUSTION AIR
500
450
400
350
300
250
200
150
100
40
0
AIR & NET STACK TEMP. deg.C
16
14
12
10
8
6
4
2
0
% O2

Figure 2

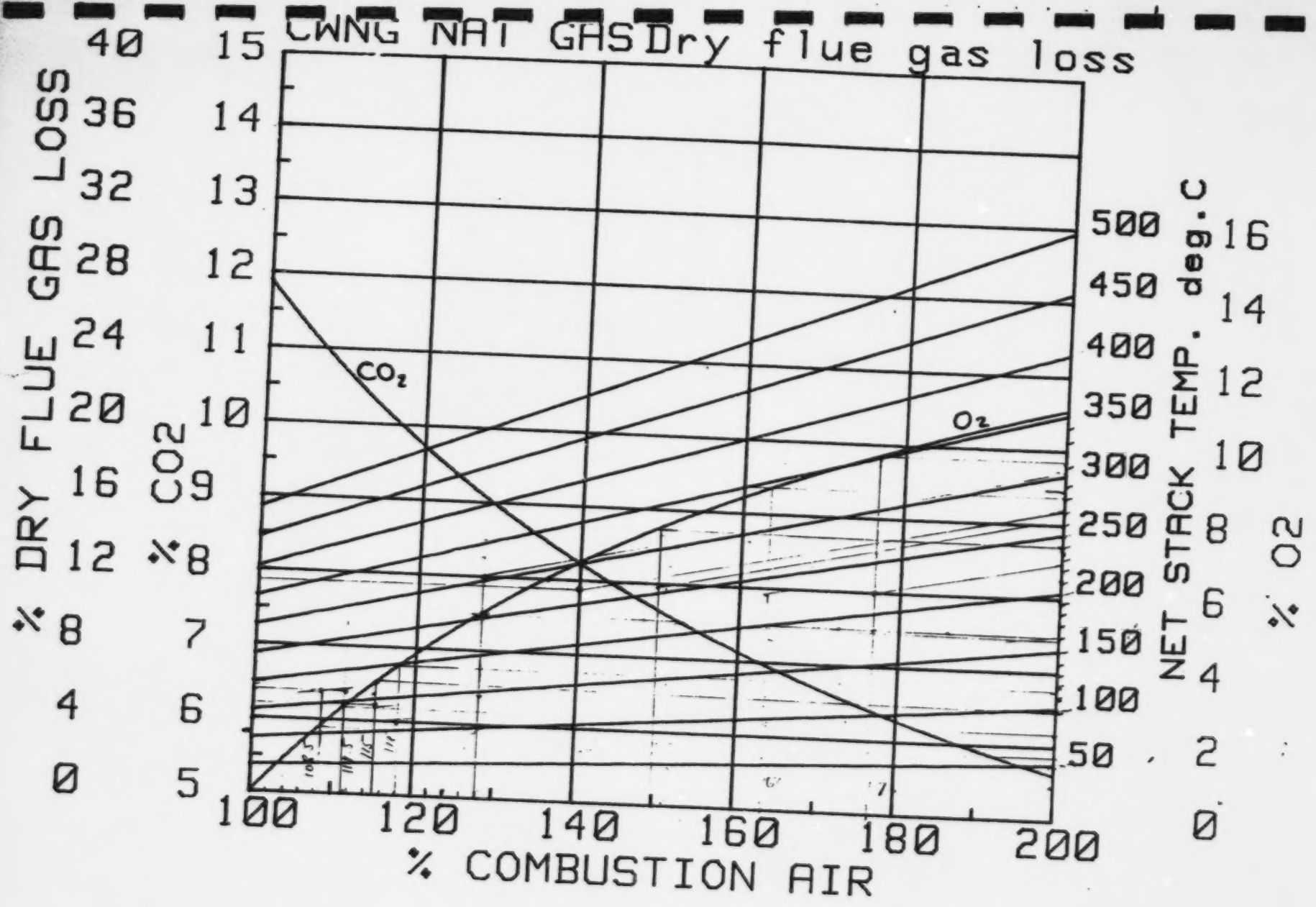

CWNG NAT GAS Dry flue gas loss
% DRY FLUE GAS LOSS
40
36
32
28
24
20
16
12
8
4
0
% CO2
15
14
13
12
11
10
9
8
7
6
5
CO2
O2
100
120
140
160
180
200
% COMBUSTION AIR
NET STACK TEMP. deg.C
500
450
400
350
300
250
200
150
100
50
% O2
16
14
12
10
8
6
4
2
0

Figure 3

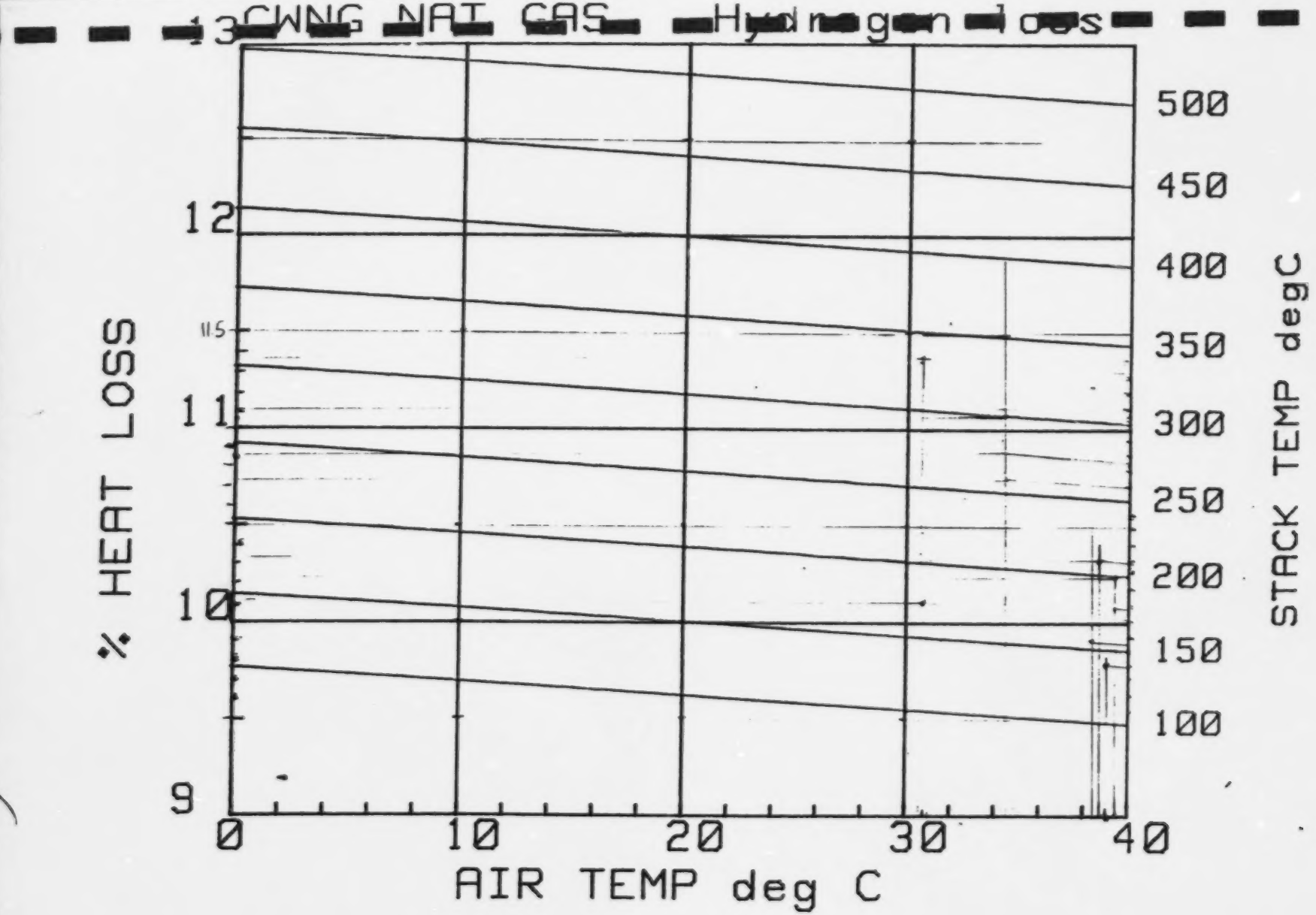

CWNG NAT GAS Hydrogen loss
13
12
11
10
9
% HEAT LOSS
0
10
20
30
40
AIR TEMP deg C
500
450
400
350
300
250
200
150
100
STACK TEMP degC

Figure 4

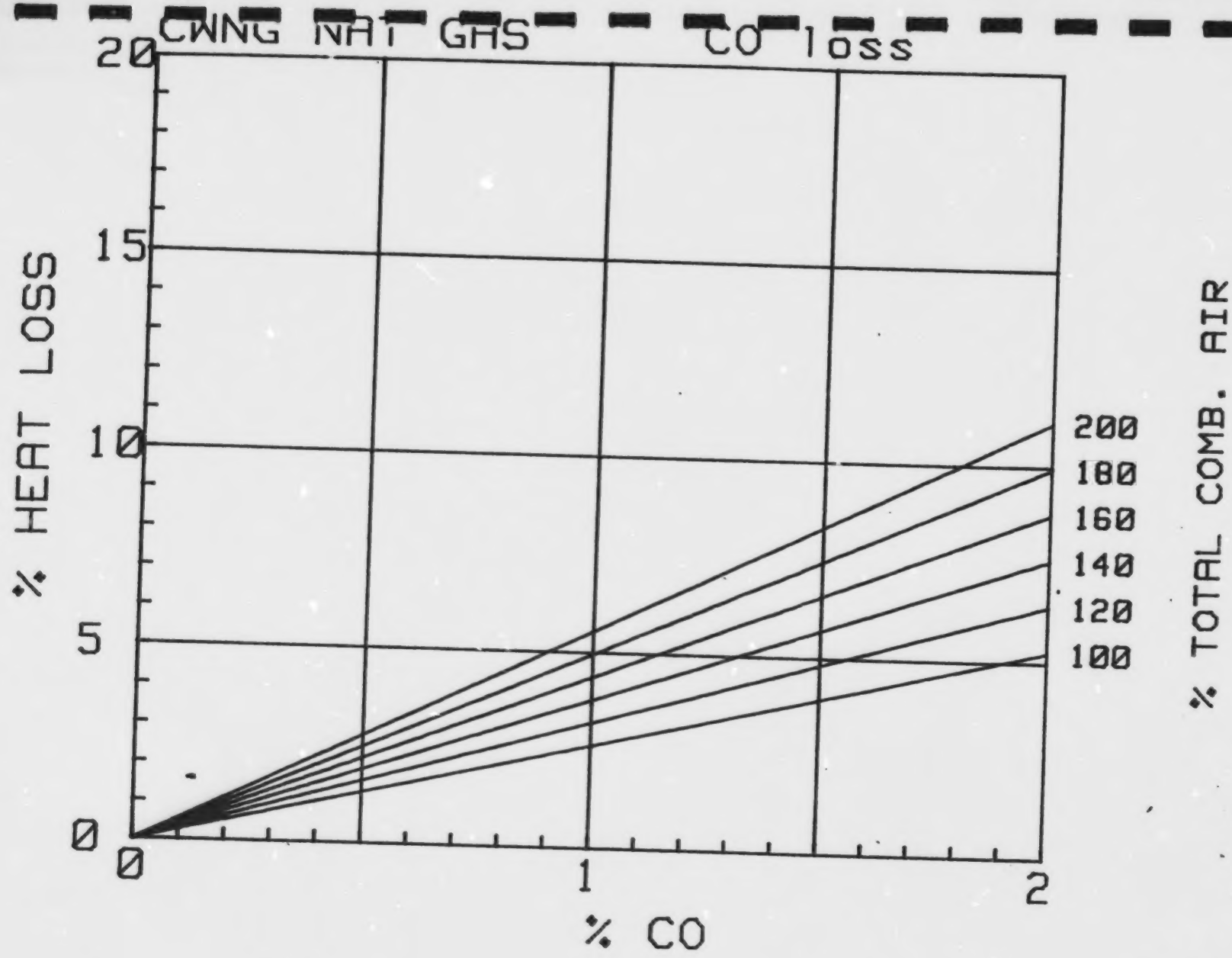

CWNG NAT GAS CO loss
% HEAT LOSS
20
15
10
5
0
0
1
2
% CO
200
180
160
140
120
100
% TOTAL COMB. AIR

Figure 5

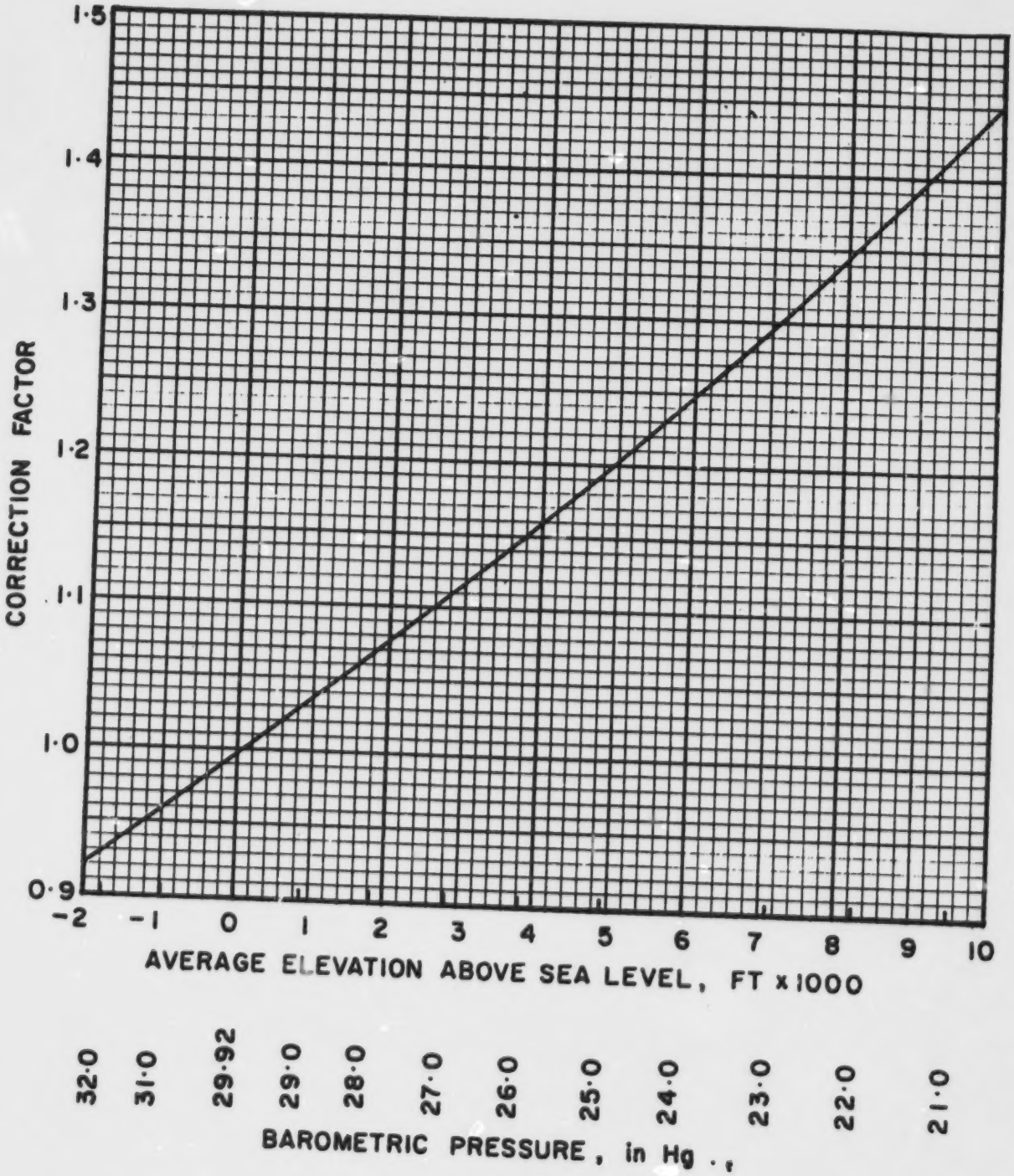


FIGURE 6. ELEVATION CORRECTION FACTORS TO BE APPLIED TO THE VOLUMES OF COMBUSTION AIR AND FLUE GAS OBTAINED FROM FIGURE 2 WHEN ATMOSPHERIC PRESSURE IS OTHER THAN 29·92 in Hg.

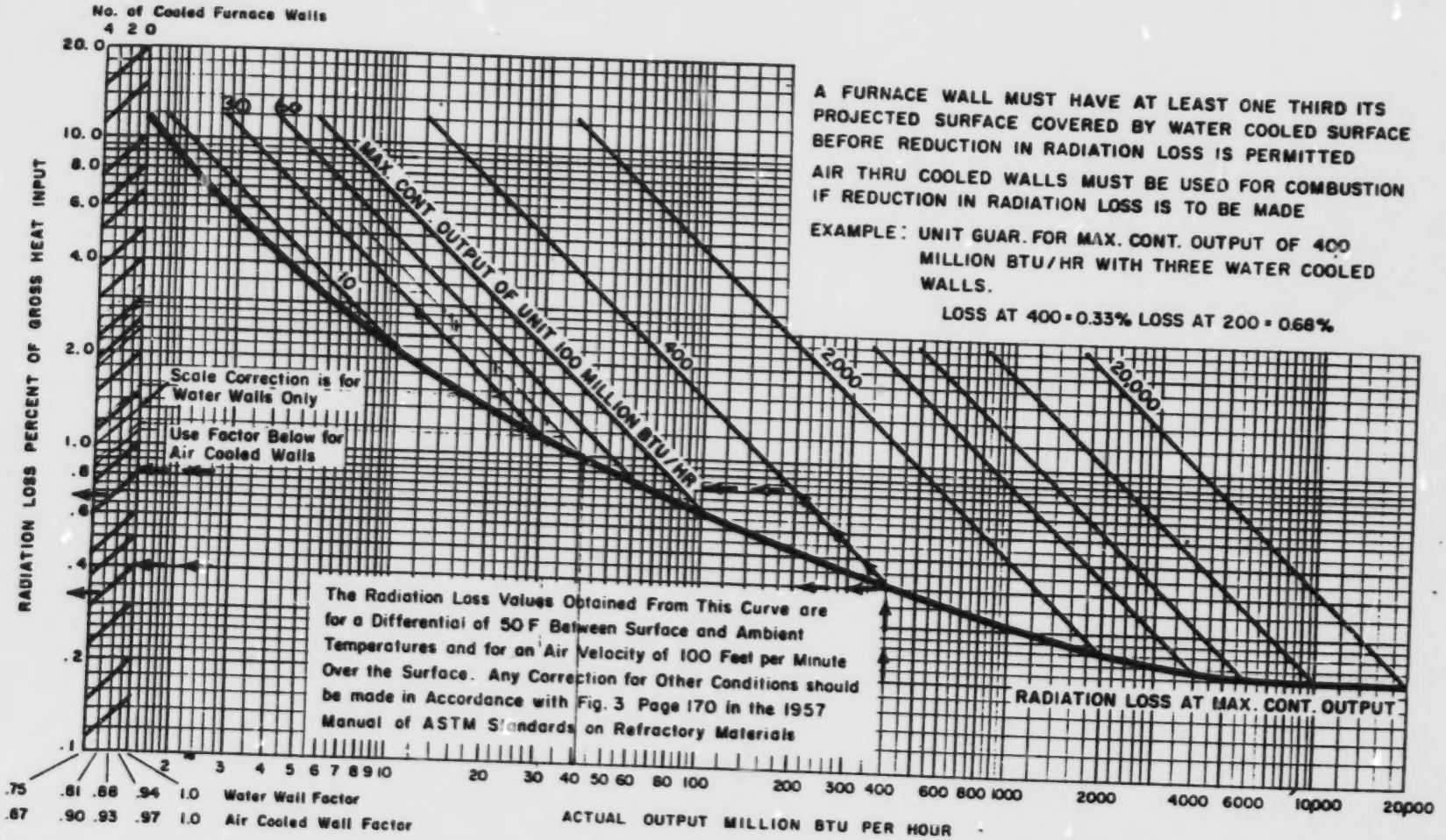
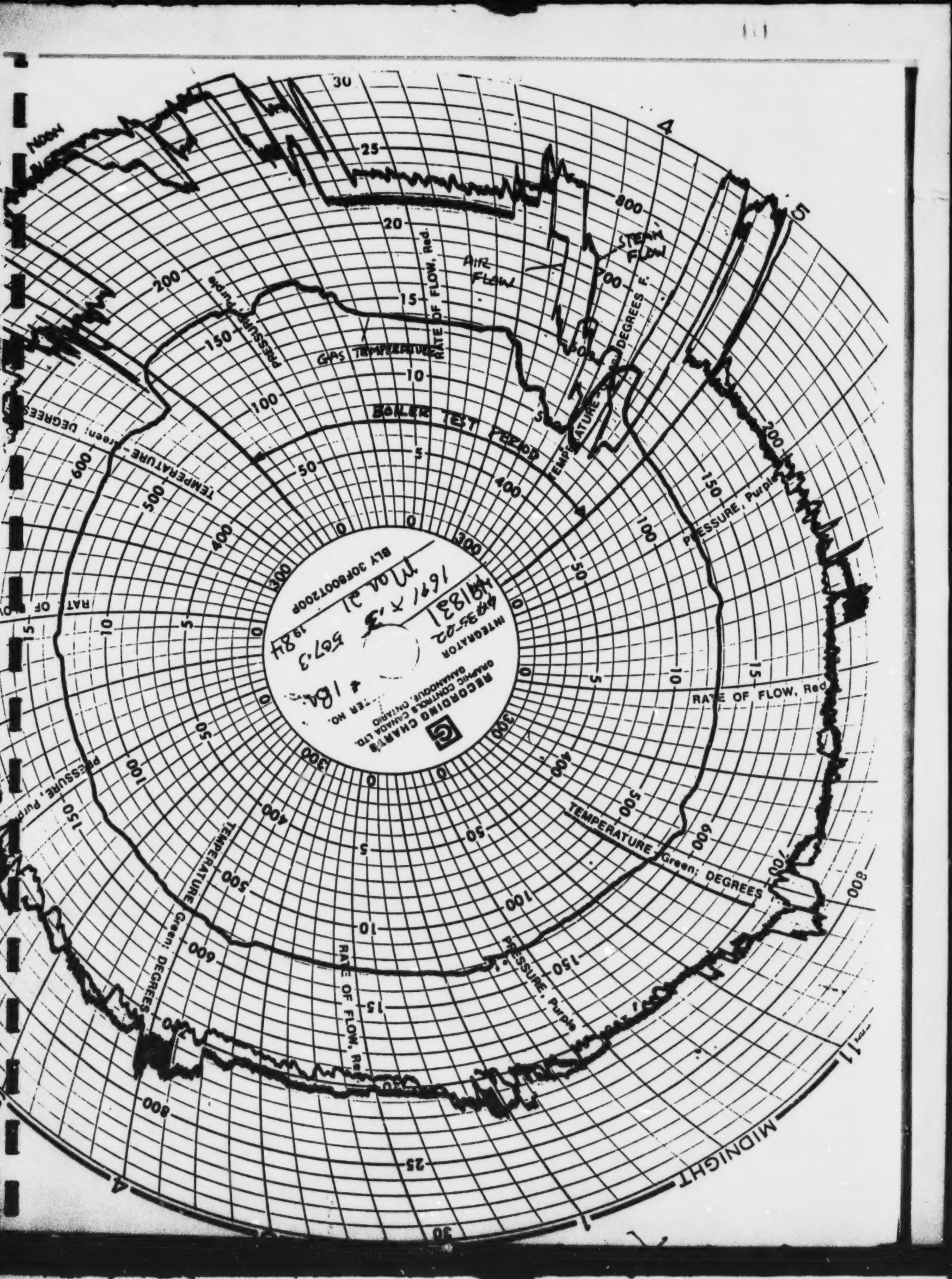
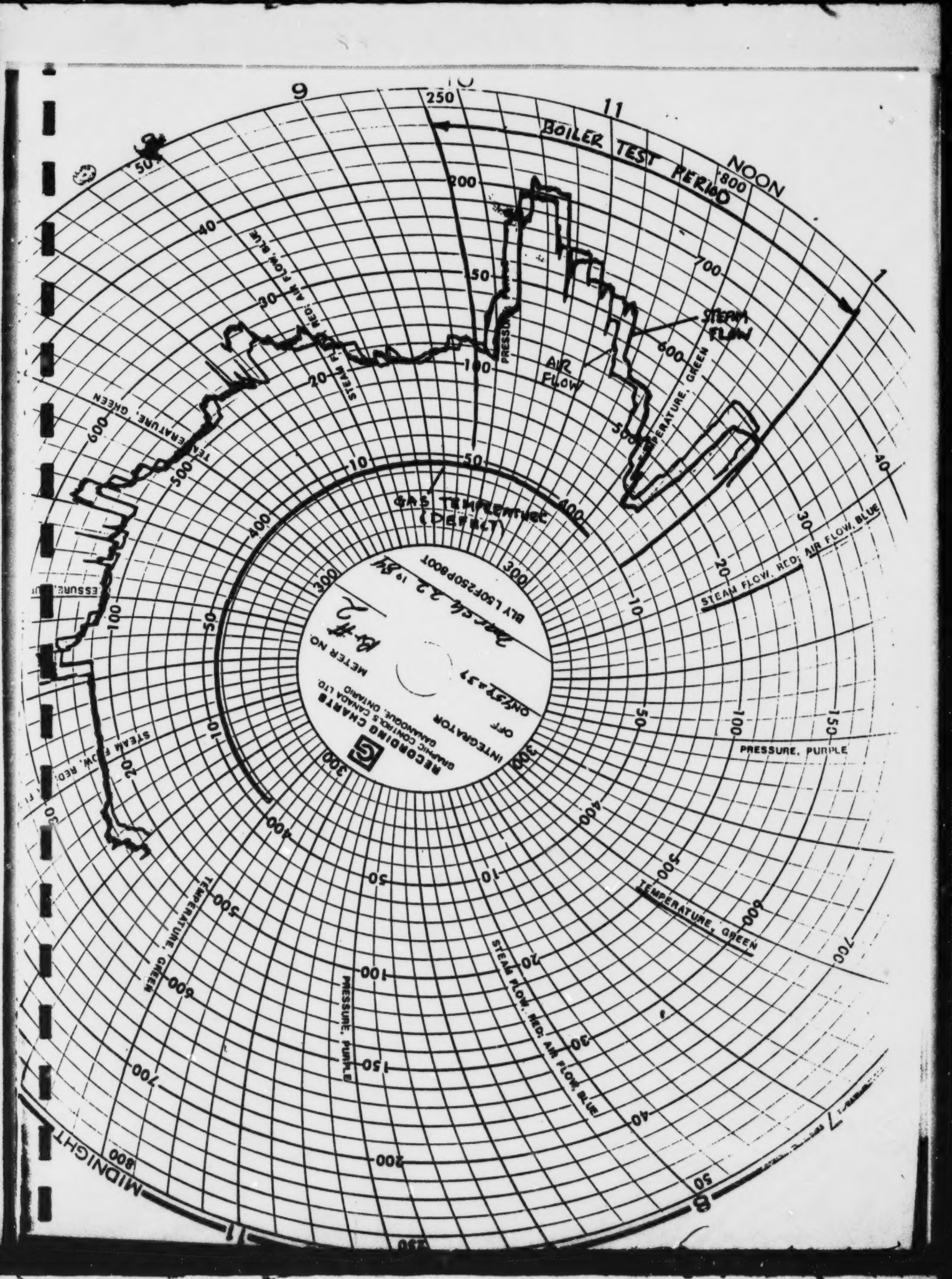

No. of Cooled Furnace Walls
4 2 0
RADIATION LOSS PERCENT OF GROSS HEAT INPUT
20.0
10.0
8.0
6.0
4.0
2.0
1.0
.8
.6
.4
.2
.1
30
20
10
MAX. CONT. OUTPUT OF UNIT 100 MILLION BTU/HR
400
2,000
20,000
A FURNACE WALL MUST HAVE AT LEAST ONE THIRD ITS PROJECTED SURFACE COVERED BY WATER COOLED SURFACE BEFORE REDUCTION IN RADIATION LOSS IS PERMITTED
AIR THRU COOLED WALLS MUST BE USED FOR COMBUSTION IF REDUCTION IN RADIATION LOSS IS TO BE MADE
EXAMPLE: UNIT GUAR. FOR MAX. CONT. OUTPUT OF 400 MILLION BTU/HR WITH THREE WATER COOLED WALLS.
LOSS AT 400 = 0.33% LOSS AT 200 = 0.68%
Scale Correction is for Water Walls Only
Use Factor Below for Air Cooled Walls
The Radiation Loss Values Obtained From This Curve are for a Differential of 50 F Between Surface and Ambient Temperatures and for an Air Velocity of 100 Feet per Minute Over the Surface. Any Correction for Other Conditions should be made in Accordance with Fig. 3 Page 170 in the 1957 Manual of ASTM Standards on Refractory Materials
RADIATION LOSS AT MAX. CONT. OUTPUT
1 2 3 4 5 6 7 8 9 10 20 30 40 50 60 80 100 200 300 400 600 800 1000 2000 4000 6000 10000 20000
.75 .81 .88 .94 1.0 Water Wall Factor
.87 .90 .93 .97 1.0 Air Cooled Wall Factor
ACTUAL OUTPUT MILLION BTU PER HOUR

FIGURE 7 RADIATION AND CONVECTION HEAT LOSS CHART, ASSUMING EMISSIVITY = 0·95
PUBLISHED BY COURTESY OF THE AMERICAN BOILER MANUFACTURERS ASSOCIATION.

APPENDIX 4

FLOW RECORDING CHARTS


NOON
MIDNIGHT
RECORDING CHARTS
GRAPHIC CONTROLS CANADA LTD.
OAKVILLE, ONTARIO
INTEGRATOR
BOILER TEST PERIOD
GAS TEMPERATURE
AIR FLOW
STEAM FLOW
RATE OF FLOW, Red.
PRESSURE, Purple
TEMPERATURE, Green; DEGREES F.
TEMPERATURE - Green; DEGREES
PRESSURE, Purple
RATE OF FLOW, Red
TEMPERATURE Green; DEGREES
PRESSURE, Purple
RATE OF FLOW, Red


BOILER TEST PERIOD
NOON
MIDNIGHT
STEAM FLOW
AIR FLOW
GAS TEMPERATURE (DEFAULT)
STEAM FLOW, RED; AIR FLOW, BLUE
PRESSURE, PURPLE
TEMPERATURE, GREEN
RECORDING CHARTS
GRAPHIC CONTROLS CANADA LTD.
GALVANOUDE, ONTARIO
INTEGRATOR
OFF
METER NO.

APPENDIX 5

BOILER DATA SHEETS

This Data Sheet issued by

BABCOCK-WILCOX and GOLDIE-McCULLOCH, LIMITED

Western Steel Ltd. Successors Ltd. Lethbridge

...conditionally loaned to ... and ... to part to furnish information from it to others as to make any use of it that is or may be injurious to Babcock-Wilcox & Goldie-McCulloch, Ltd., and to return it upon request by receiving it has agreed to ...

FUEL AS FIRED

Samples

Analyses Assumed

Kind

Class

Group

Mine

Seam

District

County

Prov. or State

Grindability

Total Moist. %

Moisture

Vol. Matter

Fixed Carbon

Ash

Total

Initial Def. pt.

Softening pt.

Liquid pt.

Fluid

Required Viscosity

Gravity °A.P.I.

Fuel Press. at Brnr.—psig.

Steam " " —psig.

Natural Gas

Sp. Gravity Relative to Air

Gas Press. at Brnr.—psig. 7.5

Temp. " "

Natural Gas

% by Volume

Ash

S

H

C

CH

C2H6 Methane 84.1

C2H4 Ethane 6.7

CO Inerts 9.2

CO2

SO2

H2S

N2

O2

Total 100.0

B.t.u. per lb. 974

B.t.u. per cu. ft. (at 60° F. & 30 in. Hg.)

EXPECTED PERFORMANCE

COL. 1 (M1) COL. 2

Steam—Actual—M lb./hr. 30

Load Duration—Hr. Cont.

Type of Fuel Natural Gas

Furnace Liberation—B.t.u./cu. ft./hr. 30.8

Excess Air leaving Unit 20

Burners—No. in use per Furnace 2

Continuous Blowdown —

Fuel M.cu.ft./hr. 41.2

Flue Gas leaving Boiler 37.2

Air entering 30.8

Min. of Feed Water 169

Drop thru Unit & Feed Valve 4

Min. oper. or Boiler P. S.V. 152

Drop from Drum to Inl. Outlet 12

Steam Stopvalve 150

Superheated Steam Superheater

Flue Gas leaving Boiler 520

" " Economizer —

" " Air Heater —

Water entering Unit 200

" leaving Economizer —

Air entering Unit 80

" leaving " " —

Furnace .10

Boiler & Screen .06

Dampers —

Economizer —

Air Heater —

Dust Collector —

Flues —

Net Draft Loss .30 1.46

Stoker or Stoker and Windbox —

Ducts —

Air Heater —

Net Resistance —

Dry Gas 2.97

Hydrogen and Moisture in Fuel 8.6

Moisture in Air 11.6

Unburned Combustible .2

Radiation —

Unacc. Loss and Mfrs. Margin —

Total Heat Loss 23.0

EFFICIENCY 77.0

Gen. Allow. Boiler Conv. P.P.M. 1500

Moist. in Steam 1.5

% Total Moisture

No. in Use per Furnace

Air Temp. to Pulverizer °F.

Pulv. & Fan ÷ Feed KW-Hr./Ton

% Thru No U.S. Sieve

" " No

Performance is based on Coal, Air and Fuel entering at 80°F., 68% rel. Humidity 0.013 lb. Moist./lb. Dry Air, 29.92 in. Hg. Barom. ...

...ry steel and ... were ... to Nov. No.

COL. 1

Unit: No. of Units — Designation — Type — Design Press. p.s.i.

Superheater: Type — No. Gas Passes — Steam Press.

Econ.: Type — Make — Design Press. p.s.i.

Air Heater: Type — Make — No. Gas Passes — No. Air Passes

Stoker: Type — Make

Pulverizer: Type — Size — No. of Outlets — Diam. in. — Fan Type — Feeder type — Size — Total Diam.

Total Volume cu. ft. — Type

Furnaces Volume and Wall Areas—Geometrical: Wall — Roof — Floor — Ends — Tot'l Area Sq. ft.

Total Heating Surface Boiler and Furnace Sq. ft.

F.D. Fan: Type — Net Requirements 30,800 lb./hr. @ 2.97 — 60°F — Test Block Specifications ... lb./hr. @ 4.35 — 105°F

I.D. Fan: Type — Net Requirements 37,200 lb./hr. @ 1.46 — 520°F — Test Block Specifications 58,800 lb./hr. @ 5.58

Stack: Height above Grade ... 50 — Construction Welded S...

Drives:

Equipment	HP	RPM	Type	
F.D.Fan	15	1750	Motor	440 60
I.D.Fan	40	1160	Motor	440 60

Revisions: No. — Description

2 2

[redacted] Wilcox Consulting Ltd

[redacted]adian Seed Processors, Lethbridge, Alta.

C 1391

EXPECTED PERFORMANCE			COL. 3
[redacted] M Lb /hr		40	EQUIPMENT
[redacted]		Continuous	
[redacted]		Natural Gas	
[redacted] K B /sq ft /hr.		65.5	
[redacted] Boiler	QUANTITIES	10 %	
[redacted]		1 BURNERS	
[redacted]		-	
(MSCFH)		51.5	
[redacted] leaving Boiler M lb/hr		42.6	
for Combustion		40.3	
[redacted] Feed Inlet	PRESSURE	167	
[redacted]ed Valve		10	
[redacted] at Boiler Drum		157	
[redacted] Drum to S.H. Outlet		7	
[redacted] Boiler		150	
[redacted] Steam		Saturated	
[redacted] leaving Boiler	TEMPERATURE	570	
[redacted] Economizer		-	
[redacted] Air Heater		354	
after entering Boiler		200	
[redacted] Economizer		-	
[redacted] Air Heater		80	
[redacted]		346	
[redacted]		-	
[redacted]	DRAFT LOSSES	1.32	
[redacted]		-	
[redacted]		-	
[redacted]		2.63	
[redacted]		-	
[redacted]		.17	
[redacted]		-	
[redacted]	AIR REQMT	6.37	
[redacted]		.25	
[redacted]		1.11	
[redacted]		12.05	
[redacted]		4.93	
[redacted] and Moisture in [redacted]	HEAT LOSSES	10.33	
[redacted] Air		.13	
[redacted]		-	
[redacted]		.31	
[redacted] and [redacted] Radiation		1.00	
Total [redacted] Loss		17.70	
EFFICIENCY		82.3	
[redacted] %		0.5	

EQUIPMENT		
UNIT	No of Units 1 Designation [redacted]	
	Type Package	
	Design Press. psig 200 Str Heating [redacted]	2430
Superheater	Type [redacted] Make	
	No. Gas Passes [redacted] No Steam Passes [redacted]	
ECON.	Type [redacted] Make	
	Design Press. psig [redacted]	
AIR HEATER	Type Tubular Make	B&W
	No Gas Passes 2 No. Air Passes 1	Gas Two Elements
BURNER STOKER	Type Circular Gas Multi-Spud Make	[redacted] 1
Pulverizer	Type Size	
	No of Outlets Diam. in.	
	Fan Type	
	Feeder type Size Inlet [redacted]	
FURNACE VOLUME Also WALL AREAS Superheater	Total Volume cu ft [redacted]	767
	WALL	
	Tot Area Sq Ft	
	Total Heating Surface [redacted] and Furnace Sq Ft	3140 To [redacted]
FD FAN	Type	
	Net Requirements 40,300 lb/hr	12.05 in of Water and 80
	Test Block Speed [redacted] 50,500 lb/hr	15.00 in of Water 105
ID FAN	Type	
	Net Requirements [redacted] lb/hr	
	Test Block Speed [redacted] lb [redacted]	
STACK	Height above [redacted] ft	
	Construction [redacted]	
	Equipment [redacted] Type [redacted]	
LOSSES		

APPENDIX 6

ECONOMIZER INSTALLATIONS IN BOILER #1
FLUE GAS DUCT

KEEPRITE - UNIFIN INC.
2610 - 3rd AVENUE N.E.
CALGARY, ALBERTA T2A 2L5

QUOTATION

WHEN REPLYING PLEASE REFER TO THIS NUMBER

No.

KeepRite Inc., Unifin Division.
P.O. Box 5395, Terminal 'A',
London, Ont., Canada N6A 4P4
Tel. (519) 451-0230. Telex 064-5664

TO MONENCO LIMITED
801 - 6th AVENUE S.W.
CALGARY, ALBERTA
T2P 3W3

DATE: April 18, 1984

YOUR REFERENCE NO. CAMBRA FOODS

ATTENTION OF JOHN SIMPSON

OUR REFERENCE NO. 45-300-84

QUANTITY	DESCRIPTION	PRICE

SUBJECT TO GENERAL TERMS AND CONDITIONS INDICATED ON REVERSE WE ARE PLEASED TO QUOTE:-

PROJECT: CAMBRA FOODS
FLUE GAS ECONOMIZER

ALTERNATIVE #1

To heat 70,000 LB/HR feedwater from 200F to 223F using 550F flue gas. Size 2-13.5-69-2-2 economizer.

NET PRICE ----- $3,220.00
WEIGHT ----- 760 POUNDS

"See specification sheet and sketch 840307-100"

ALTERNATIVE #2

To heat 70,000 LB/HR. feedwater from 200F to 230F using 550F flue gas. Size 3-13.5-69-2-2 economizer.

NET PRICE ----- $5,320.00
WEIGHT ----- 1140 POUNDS

"See specification sheet and sketch 840307-200

ESTIMATED TIME OF DELIVERY: 10 weeks

F.O.B. LONDON, ONTARIO

FREIGHT EXTRA

Per

C.A. PINKERTON C.E.T.
SALES REPRESENTATIVE

COMMENTS

1. Base bid is for coils only. Mounting and inter connecting piping by others.

2. Base bid utilizes extruded aluminum fin tube. Tubewall temperature maximum is 450F; therefore; feedwater must be on before and during the flue gas being on. An alternative will be supplied using "IMBEDDED" FIN TUBE.

3. Gas side pressure drop is .9" Wg. for alternative 1 and 1.25" Wg. for alternative 2.

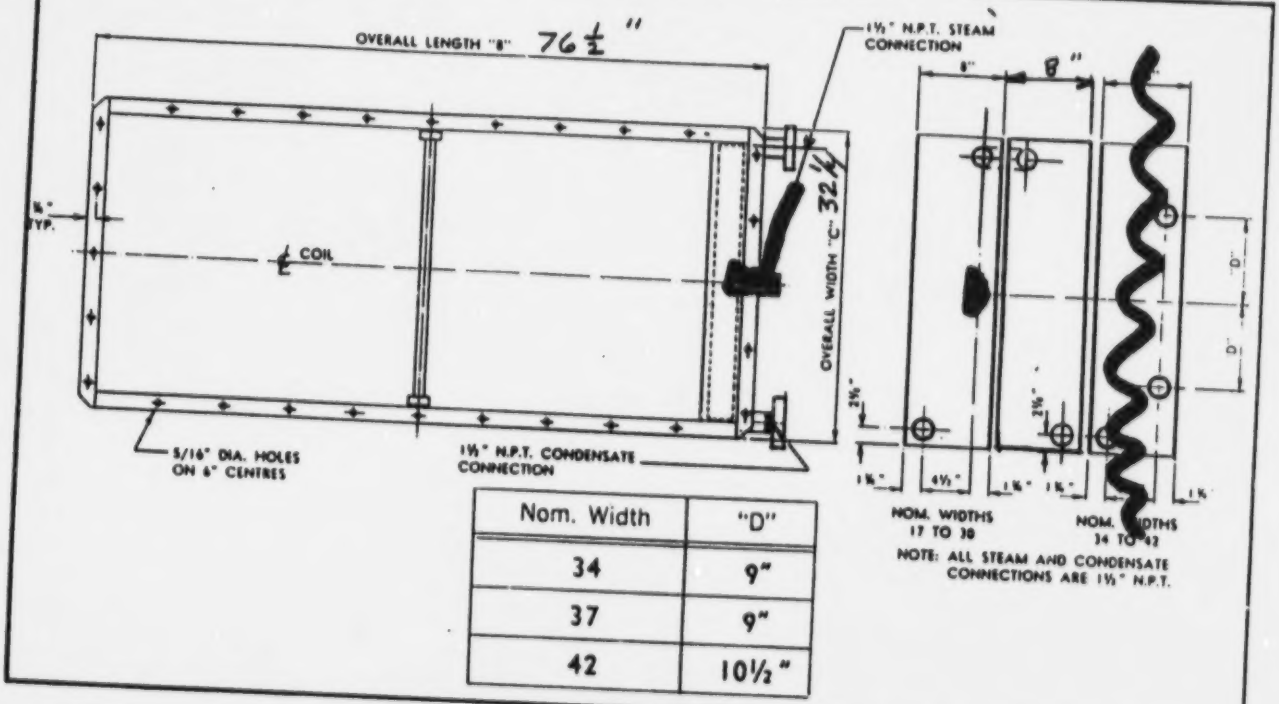
4. Tubes are 1" od x .083" wall steel c/w 5 FPI extruded aluminum fins. Headers are steel with flanged connections. Casings are galvanized steel.

840307-100

TECHNICAL DATA

KeepRite Unifin

TYPE H – Same End Connections – 1" O.D - Liner Tube


OVERALL LENGTH "B" 76½"
1½" N.P.T. STEAM CONNECTION
8"
8"
OVERALL WIDTH "C" 32¼
COIL
5/16" DIA. HOLES ON 4" CENTRES
1½" N.P.T. CONDENSATE CONNECTION
NOM. WIDTHS 17 TO 30
NOM. WIDTHS 34 TO 42
NOTE: ALL STEAM AND CONDENSATE CONNECTIONS ARE 1½" N.P.T.

Nom. Width	"D"
34	9"
37	9"
42	10½"

TABLE 10 – Dimensions and Approximate Dry Weights*

Nominal Ordering Width	"C" Overall Width	Number of Tubes	Nom. Ordering Length / Overall Length "B"	25 / 32⅛	31 / 38⅛	37 / 44⅛	43 / 50⅛	49 / 56⅛	55 / 62⅛	61 / 68⅛	67 / 74⅛	73 / 80⅛	79 / 86⅛	85 / 92⅛	91 / 98⅛	97 / 104⅛	103 / 110⅛	109 / 116⅛	115 / 122⅛	121 / 128⅛
17	20⅝"	8	Face Area	2.0	2.6	3.3	3.9	4.6	5.2	5.9	6.5	7.2	7.8	8.5	9.1	9.8	10.4	11.1	11.7	12.4
			Weight	94	106	118	130	142	161	173	185	197	209	228	241	253	265	277	294	306
20	24⅜"	10	Face Area	2.5	3.2	3.9	4.6	5.3	6.0	6.7	7.4	8.1	8.8	9.5	10.2	10.9	11.6	12.3	13.1	13.8
			Weight	111	125	140	154	168	191	206	220	234	248	271	285	300	314	328	348	363
26	29"	12	Face Area	3.2	4.0	4.8	5.5	6.3	7.1	7.9	8.7	9.5	10.3	11.1	11.9	12.6	13.5	14.3	15.2	16.0
			Weight	129	145	162	178	195	222	238	255	271	288	315	331	348	364	381	403	420
30	33¼"	14	Face Area	3.9	4.8	5.7	6.7	7.6	8.6	9.5	10.5	11.4	12.3	13.3	14.2	15.1	16.1	17.0	18.0	18.9
			Weight	146	165	184	203	221	252	271	290	308	327	358	377	395	414	433	457	476
34	37⅛"	16	Face Area	4.6	5.7	6.8	7.9	9.0	10.1	11.2	12.3	13.4	14.5	15.6	16.7	17.8	18.9	20.0	21.1	22.2
			Weight	165	186	207	226	249	283	304	325	346	367	402	423	444	465	486	513	534
37	40¼"	17	Face Area	5.0	6.2	7.4	8.5	9.7	10.9	12.1	13.2	14.4	15.6	16.8	17.9	19.1	20.3	21.4	22.6	23.8
			Weight	175	197	219	241	263	288	322	344	368	389	425	447	469	492	514	542	564
42	45⅞"	20	Face Area	5.8	7.2	8.6	10.0	11.4	12.8	14.2	15.6	17.0	18.5	19.9	21.3	22.7	24.1	25.5	27.0	28.4
			Weight	200	225	251	278	302	344	368	395	420	446	488	513	539	564	590	621	647

TABLE 11

Tube Type	Dimensions	Material	Design Pressure	WEIGHT CORRECTION FACTORS* 5 FPI	9 FPI	11 FPI
1	1" O.D. x .049" Wall	90/10 Cupro-Nickel	300	-2.2	See Table 10	+3.2
2	1" O.D. x .083" Wall	Steel	300	+2.5	+3.15	+3.4
3	1" O.D. x .049" Wall	316 S.S.	200	-0.6	-.52	+2.7

***SHIPPING WEIGHT CORRECTIONS:** Weights shown in Table 10 apply to 9 FPI coils with Type 1 tubes. For weights of other coils add or subtract (as applicable) the product of the FACE AREA x CORRECTION FACTOR.

CONSTRUCTION: (1) Finned tubing to be aluminum integral fins on 1" O.D. liner. See Table 11 for wall thickness and material.

(2) Tube to header joints are silver soldered for cupro-nickel tubing and welded for steel and stainless steel tubing.

(3) Headers fabricated from carbon steel for tube Type 1, 2 and 304 stainless steel for tube Type 3.

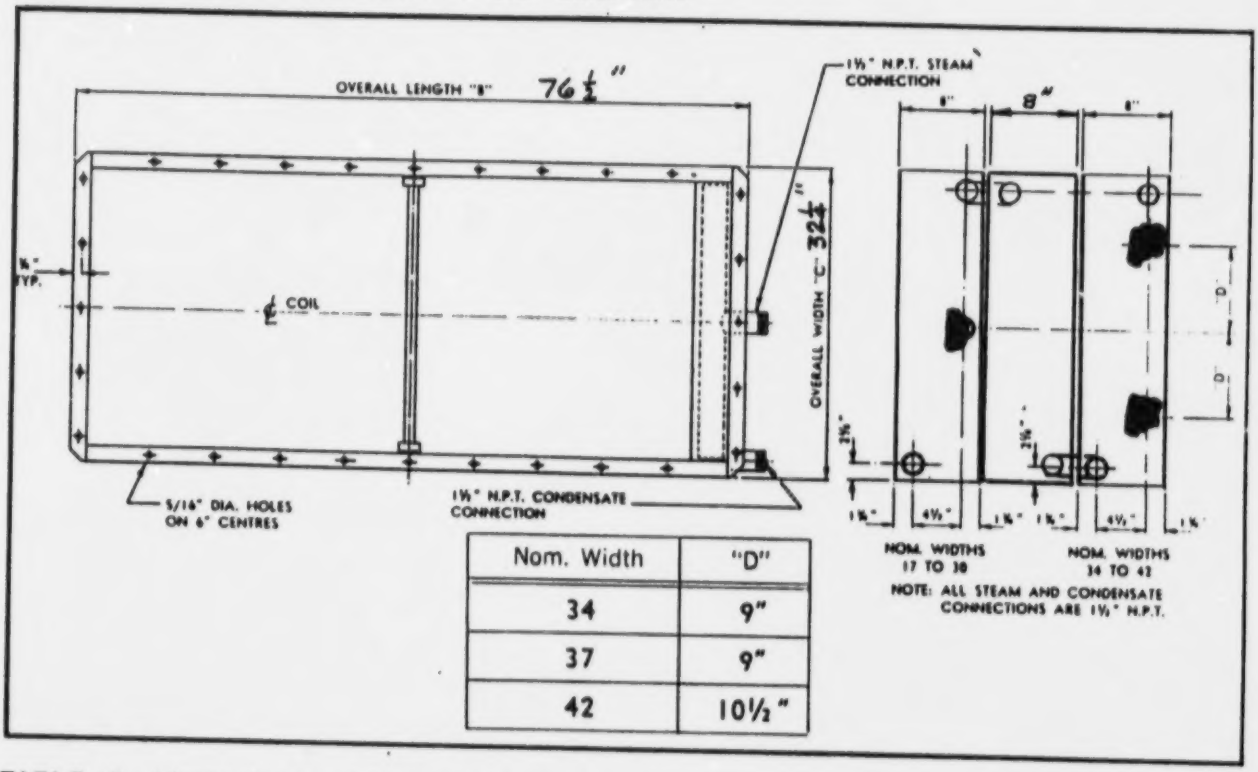
(4) Casing fabricated from commercial grade galvanized sheet steel.

840307-200

TECHNICAL DATA

KeepRite Unifin

TYPE H – Same End Connections – 1" O.D - Liner Tube



Nom. Width	"D"
34	9"
37	9"
42	10½"

TABLE 10 – Dimensions and Approximate Dry Weights*

Nominal Ordering Width	"C" Overall Width	Number of Tubes	Nom. Ordering Length	25	31	37	43	49	55	61	67	73	79	85	91	97	103	109	115	121
			Overall Length "B"	32½	38½	44½	50½	56½	62½	68½	74½	80½	86½	92½	98½	104½	110½	116½	122½	128½
17	20⅝"	8	Face Area	2.9	3.6	4.3	5.1	5.8	6.5	7.2	8.0	8.7	9.4	10.2	10.9	11.6	12.4	13.1	13.8	14.6
			Weight	94	106	118	130	142	161	173	185	197	209	228	241	253	265	277	294	306
20	24¾"	10	Face Area	3.5	4.5	5.4	6.3	7.2	8.1	9.0	9.9	10.8	11.7	12.6	13.5	14.4	15.3	16.2	17.1	18.0
			Weight	111	125	140	154	168	191	205	220	234	248	271	285	300	314	328	348	363
26	29"	12	Face Area	4.2	5.3	6.4	7.5	8.6	9.6	10.7	11.8	12.9	14.0	15.1	16.1	17.2	18.3	19.4	20.5	21.6
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			Weight	148	165	184	203	221	252	271	290	308	327	358	377	395	414	433	457	476
34	37½"	16	Face Area	5.6	7.0	8.5	9.9	11.3	12.8	14.2	15.6	17.1	18.5	20.0	21.4	22.8	24.3	25.7	27.1	28.6
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			Weight	175	197	218	241	263	300	322	344	366	389	425	447	469	492	514	542	564
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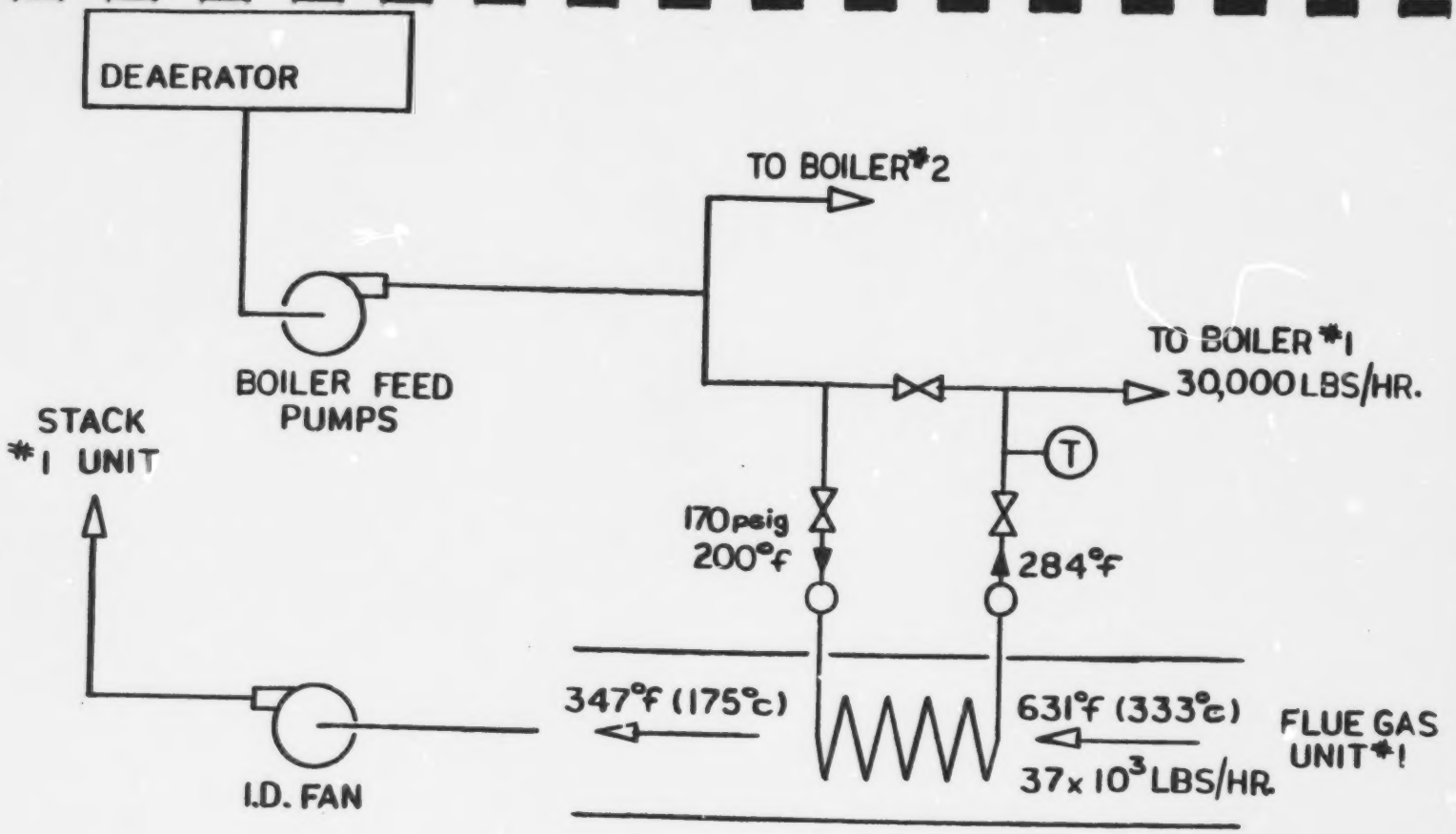
(2) Tube to header joints are silver soldered for cupro-nickel tubing and welded for steel and stainless steel tubing.

(3) Headers fabricated from carbon steel for tube Type 1, 2 and 304 stainless steel for tube Type 3.

(4) Casing fabricated from commercial grade galvanized sheet steel.



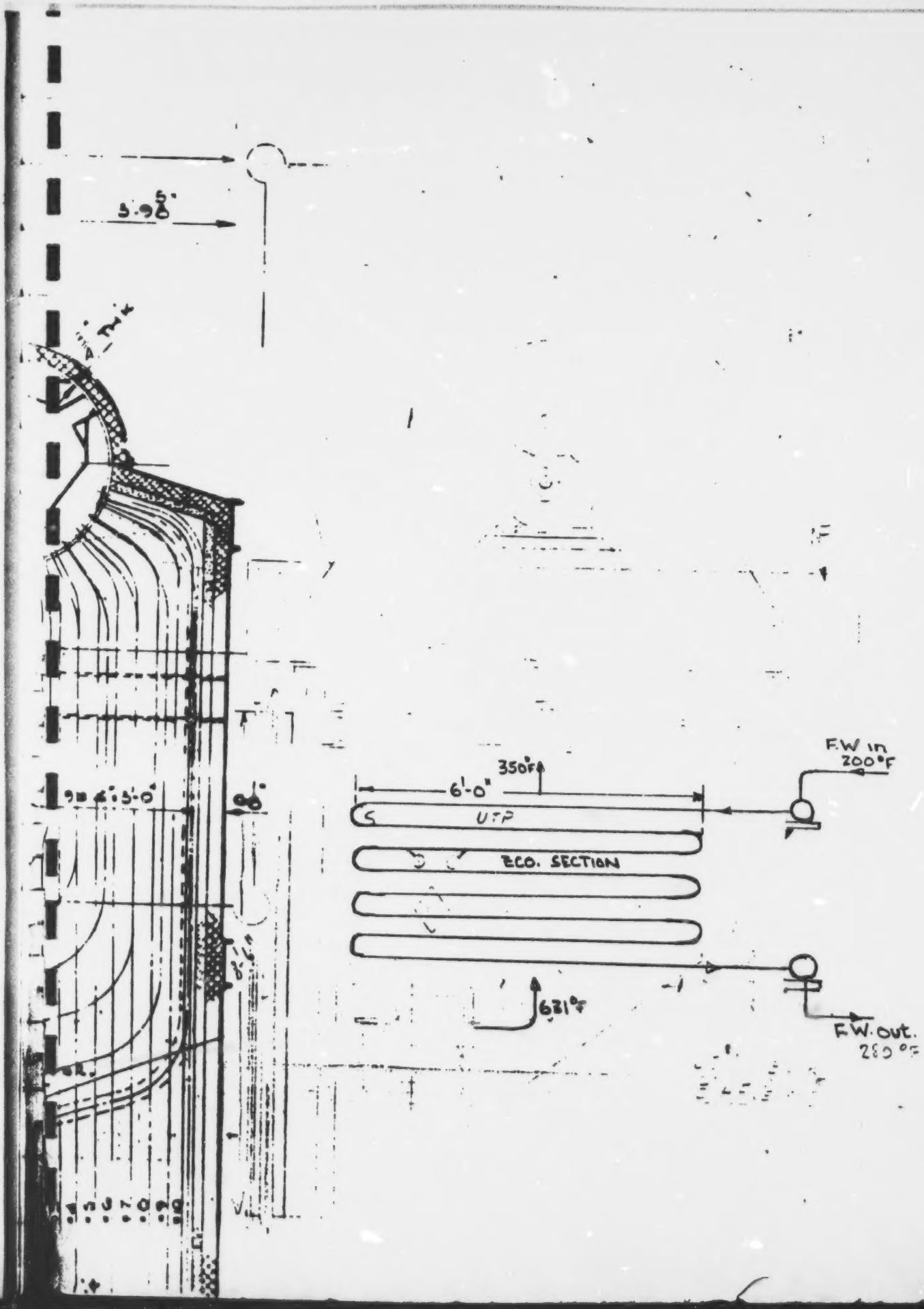
LOW DIAGRAM— ECO. SECTION IN BOILER #1 FLUE GAS DUCT.

$$(m.C_p.\Delta T)_{FLUE\ GAS} = (m.C_p.\Delta T)_{BFW}$$

$$37 \times 10^3 \times 0.24 \times 284 = 30 \times 10^3 \times 1 \times \Delta T$$

$$\Delta T = \frac{37 \times 10^3 \times 0.24 \times 284}{30 \times 10^3}\ ^\circ F$$

$$\underline{\Delta T = 84\ ^\circ F}$$


D
5.98
9'-5"
350°F
6'-0"
U.T.P
ECO. SECTION
621°F
F.W in
200°F
F.W. out.
280°F

J.S.K

Babcock & Wilcox Canada

Babcock & Wilcox Industries Ltd. a McDermott company

Suite 605 Gulf Canada Square
401-9th Avenue S W
Calgary, Alberta T2P 3C5
(403) 263-5964
Telex: 038-21887

April 27, 1984

Monenco Consultants Limited
400 Monenco Place, 801 - 6th Ave. S.W.
CALGARY, Alberta T2P 3W3

ATTENTION: Mr. R.A. Bennett, P. Eng.
Manager
Mechanical Engineering Department

SUBJECT: Enersolve Demonstration Project
Canbra Foods Ltd., Lethbirdge
Babcock & Wilcox Ref. RW-1463

Gentlemen:

Further to your letter of April 5, 1984, we have reviewed the drawings and data sheets for the two units involved and our comments concerning each are as follows:

B & W Contract 6391 - Gas Fired FM 9-57 boiler capacity 40,000 pph steam. The unit is presently equipped with a tubular air heater and a circular gas multispud burner for firing natural gas. Design excess air is 10% and the air heater exit gas temperature is 346°F.

From a design point of view there is nothing to be added to this unit to substantially improve the original anticipated efficiency of 82.3%, taken from the data sheets.

We would, however, advise the addition of an 02 trim system for this unit, which enable the operators to better maintain the 10% excess air the unit was originally designed to operate at.

B & W Contract 4753 - Bi Drum Brickset Unit originally equipped with a dutch oven, since removed - capacity 30,000 pph steam firing natural gas. This unit is presently equipped with two 15½" ring type gas burners with a boiler exit gas temperature of 520°F and a design excess air of 20%.

This unit could be equipped with a feedwater heater and economizer and with careful attention to reducing the furnace leakage i.e.: through the brick work and casings, it is possible that the efficiency could be improved.

...2

We would suggest a cylindrical stack mounted type of economizer as this would create the minimum disruption to the existing gas flue arrangement.

Based on other bids of a similar size, the feedwater heater, control valves and economizer would cost approximately $40,000.00 material and $30,000.00 installation, depending upon onsite conditions. This would reduce the boiler exit gas temperature to around 350°F for about 6 points improvement in efficiency. The economizer would require a 42" diameter stack, however, if not available transition pieces could be used to match existing diameters.

Design modification to the burners and controls, other than the 02 trim system noted above would probably do little to improve the design efficiency of this unit as the remote cased tube and tile setting is not the ideal arrangement for lowering excess air.

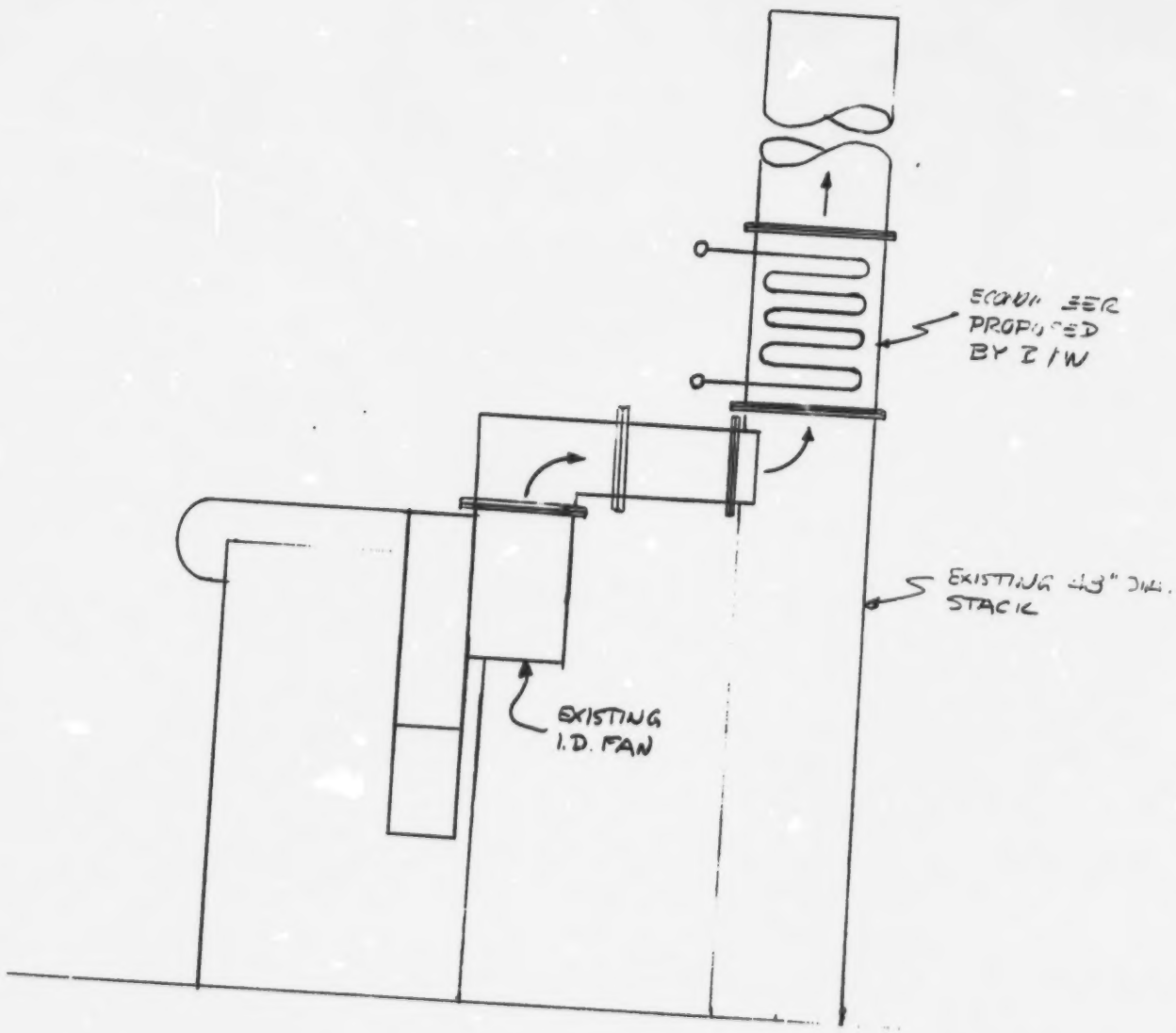
We would suggest that the next step in this process would be to have B & W's field service personnel do a boiler fitness survey to establish the current operating mode and problems, if any. We would be more than pleased to supply you with the required personnel on a daily rate basis and issue you with the appropriate report upon completion.

In the meantime should you have further queries concerning this project, please do not hesitate to contact us.

Yours very truly,
BABCOCK & WILCOX CANADA

P. B. Nelson
Sales Representative
Operating Equipment Services

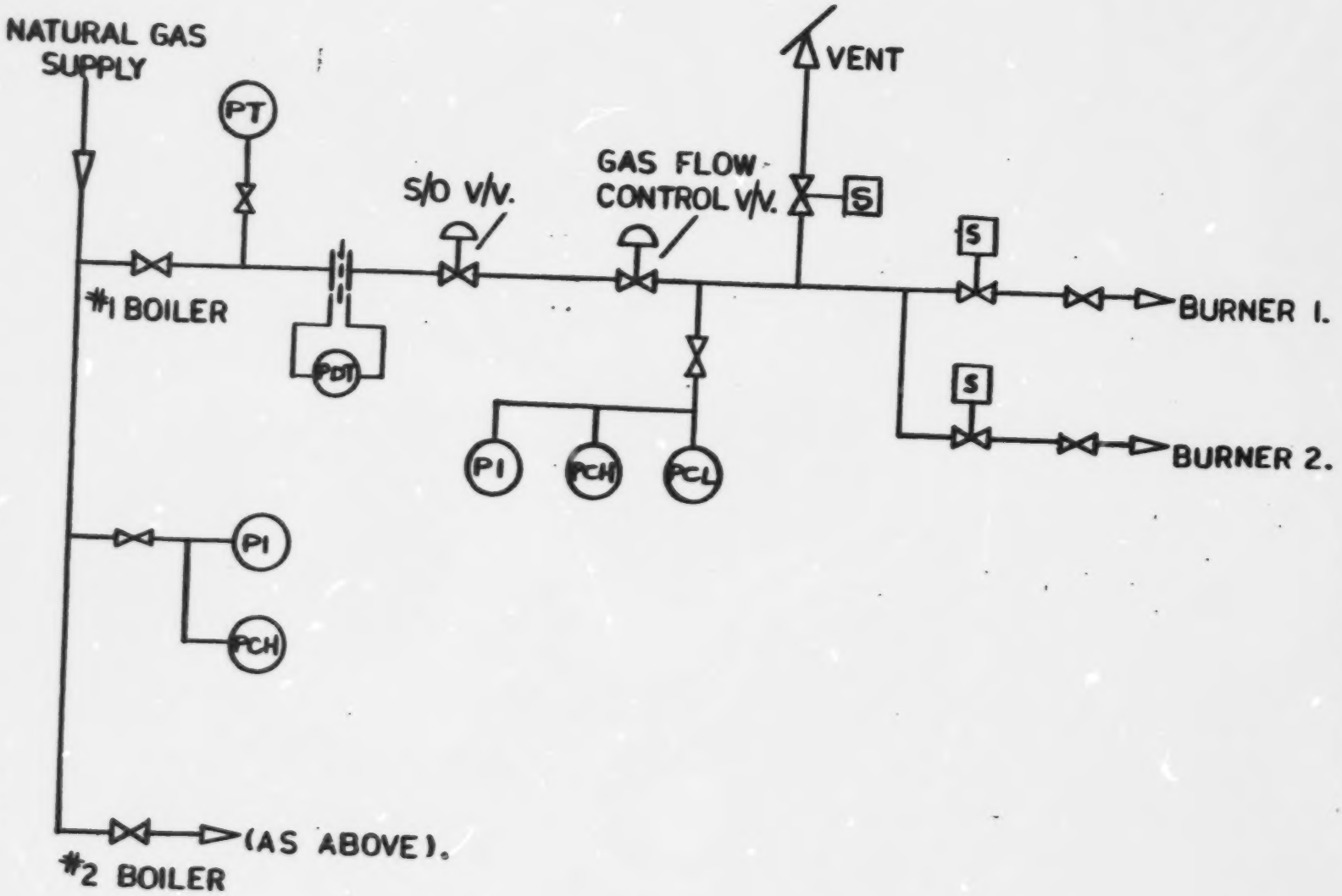
PBN/skf



EXISTING
BOILER Nº 1

APPENDIX 7

FLOW DIAGRAM - NATURAL GAS LINE



FLOW DIAGRAM — NATURAL GAS LINE.

APPENDIX 8

INSTRUCTION MANUAL FOR COMBUSTION GAS ANALYZER

INSTRUMENT No.
I.W. 2023
Wirtanen Electric Co. Ltd.

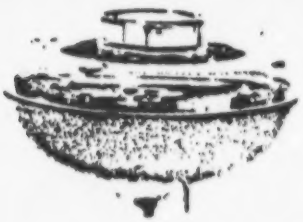
WIRTANEN
ELECTRIC (1962) LTD.

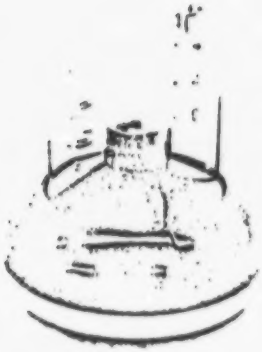
ALBERTA **EDMONTON** CANADA

Electrical **INDUSTRIAL** Mechanical
INSTRUMENTATION MAINTENANCE INSTALLATIONS
Rentals **SERVICE** Sales

INSTRUCTIONS 11-9026
OPERATION/MAINTENANCE
BACHARACH FYRITE MODELS
CO_2 and O_2 INDICATORS
JANUARY 1980

Bacharach FYRITE®
Gas Analyzers
For Measuring Carbon Dioxide (CO_2) Or Oxygen (O_2)





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TELEPHONE: (412) 782-3500

UNITED TECHNOLOGIES BACHARACH

FYRITE SAFETY PRECAUTIONS

The operator(s) of this instrument should thoroughly familiarize themselves with the required safety precautions applicable before handling the FYRITE or its use for gas analysis.

Review Figures 1a, 1b, 1c, and 1d located in the front and back of this manual. Make certain to follow the steps outlined below and read the fluid handling precautions for your personal safety.

1) Always use protective equipment such as safety goggles, gloves, and protective clothing as illustrated in Fig. 1a.

2) Read the instruction manual thoroughly. When filling the FYRITE with the applicable fluid charge, use safety equipment and perform this operation in the vicinity of running tap water (see Fig. 1b).

3) The FYRITE fluid should always be in the bottom reservoir before and during sample introduction to the FYRITE. When venting the FYRITE to atmosphere, hold the instrument in the vertical position and at a location away from your face (see Fig. 1c).

4) NEVER vent the FYRITE in the inverted position (with the plunger facing downward). This would cause spill of the fluid which is corrosive and contains harmful elements (see Fig. 1d).

NOTE: In the event of fluid spill — refer to Sec. 2.2., FYRITE Fluid Handling Precautions. For Maintenance — refer to Sec. 6.0.

Figure 1a: Illustrating protective equipment required before attempting gas analysis.

Figure 1b: Preparing to fill FYRITE using recommended protective safety equipment.

CAUTION

CORROSIVE FLUID IS CONTAINED INSIDE UNIT, INSTRUCTIONS SHOULD BE THOROUGHLY READ BEFORE OPERATION IS ATTEMPTED.

WARRANTY

We guarantee every FYRITE to be free from defects in material or workmanship for a period of one year. If the instrument develops such defects within one year from date of shipment from our plant, it will be repaired or replaced if it is returned to our factory, transportation charges prepaid. This warranty, however, does not apply to damage due to misuse or careless handling. Furthermore, we do not assume liability for indirect or consequential damage or loss of any nature in connection with equipment sold by us.

This warranty does not apply to products or parts which are expendable in normal use or have a limited shelf life, such as FYRITE Fluid, Wool packing, O-rings, Gaskets, Sampling Assemblies or other items as indicated in the related Operating Instructions.

FYRITE, TRUE-SPOT, DRAFTRITE, TEMPOINT, FLORITE, FLORET, SERDEX, TEMPSCRIBE, are registered trademarks of the Bacharach Instrument Company.

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OPERATION/MAINTENANCE
BACHARACH FYRITE MODELS
CO_2 and O_2 INDICATORS
JANUARY 1980

1.0 INTRODUCTION

The FYRITE employs the well-known "Orsat" method of volumetric analysis involving chemical absorption of a sample gas, such as carbon dioxide or oxygen. The reagent used to absorb carbon dioxide (CO_2) is potassium hydroxide (dyed red), and chromous choloride (blue) is the absorbent for oxygen (O_2).

The unique feature of the FYRITE is that the absorbing fluid is also used as the indicating fluid so that one vessel takes the place of both measuring burette and absorption pipette.

1.1 Description (refer to Figure 1)

The body of the FYRITE is molded of clear high-strength plastic, comprises top and bottom reservoirs and a center tube connecting the two reservoirs. The bottom of the lower reservoir is sealed off by a synthetic rubber diaphragm which rests on a perforated metal plate. The upper reservoir is covered by a molded plastic cap which contains a double-seated plunger valve. A spring holds this valve against a carefully finished seat in the top cap providing a perfect seal which makes the instrument spillproof in any position. When the valve is partially depressed, the entire instrument is open to the atmosphere and the instrument is, of course, no longer spillproof.

The bottom reservoir is filled with the absorbing fluid which extends about ¼ inch into the bore of the center tube when the instrument is held upright.

The scale position, mounted to one side of the center tube, is adjustable.

2.0 FYRITE INSPECTION BEFORE AND DURING TEST

CAUTION

CORROSIVE FLUID IS CONTAINED INSIDE UNIT, INSTRUCTIONS SHOULD BE THOROUGHLY READ BEFORE OFERATION IS ATTEMPTED.

2.1 Pre-operational Check

To ensure proper FYRITE operation and reliable results, check the following:

(a) FYRITE Fluid Level - with FYRITE in vertical position top of fluid column should not be less than ⅛ inch or more than ⅜ inch above the bottom of the small center FYRITE bore, in order to permit scale zero adjustment.

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The bottom reservoir is filled with the absorbing fluid which extends about ¼ inch into the bore of the center tube when the instrument is held upright.

The scale position, mounted to one side of the center tube, is adjustable.

2.0 FYRITE INSPECTION BEFORE AND DURING TEST

CAUTION

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2.1 Pre-operational Check

To ensure proper FYRITE operation and reliable results, check the following:

(a) FYRITE Fluid Level - with FYRITE in vertical position top of fluid column should not be less than ⅛ inch or more than ⅜ inch above the bottom of the small center FYRITE bore, in order to permit scale zero adjustment.

With FYRITE vented and in vertical position, it should be possible to adjust scale zero to top of fluid column. If this is not possible, add or remove small amount of fluid as per Section 6.1.

(b) FYRITE Fluid Strength

To check fluid strength.

NOTE: WHEN REPEATING PROCEDURES AS OUTLINED IN SECTION 3.0 STEPS 7 THROUGH 9 (ABSORBING AND READING PERCENT O_2 AND ABSORBING AND READING PERCENT CO_2) AND BEFORE VENTING FYRITE TO ATMOSPHERE FOR NEXT SAMPLE, IF THE READING INCREASES BY MORE THAN ½ PERCENT FOR EITHER CO_2 OR O_2 REPLACE FLUID.

It is often desirable to check fluid strength before taking FYRITE to location where it will be used. It can be tested on sample atmospheric air (which contains 20.9% O_2). Be certain to wet Filter Saturator when checking atmospheric air for maximum accuracy. (See Section 6.9)

O_2 (Oxygen) Fluid. Fresh FYRITE fluid will absorb all O_2 from approximately 100 samples containing 10% O_2 .

CO_2 (Carbon Dioxide) Fluid. Fresh FYRITE Fluid will absorb all CO_2 from approximately 350 samples containing 10% CO_2 .

(c) FYRITE Sampling Assembly - Always check sampling assembly for proper (leak-free) operation as outlined in Section 6.7 before proceeding with test.

(d) Make certain wool in Filter Saturator Tube is moistened with water if using either O_2 or CO_2 FYRITE in a noncombustible application where gas sample is not fully saturated with water vapor. Examples where filter-saturator must be wetted include measuring CO_2 or O_2 in ambient air or from compressed gas samples. Refer to Section 6.9 when replacing or moistening saturator (wool) filter is required.

FYRITE OPERATION PRECAUTION: To prevent fluid spill, never depress Plunger Valve to vent FYRITE when unit is in the inverted or any other non-upright position. When depressing Plunger Valve in the upright position to vent FYRITE, hold at a slight angle away from the operator's face.

2.2 FYRITE Fluid Handling Precautions

CAUTION: FYRITE FLUIDS USED IN THE CO_2 AND O_2 ANALYZERS ARE CORROSIVE AND CONTAIN POISONOUS ELEMENTS WHICH MUST NOT BE TAKEN INTERNALLY. IN THE EVENT OF A SPILL OR ACCIDENTAL BODY CONTACT WITH FYRITE FLUID, READ THE FOLLOWING CAREFULLY (REPRINTED FROM LABEL ON EACH REFILL BOTTLE).

CO_2 FYRITE Indicator Fluid Only

POISON

Contains Potassium Hydroxide

ANTIDOTE

External - Flood with water, then wash with vinegar.
Internal - Give vinegar; or juice of lemon, grapefruit, or orange copi ously. Follow with olive oil.
Eyes - Flood with water, then wash with 5% boric acid solution.

CALL PHYSICIAN

O_2 FYRITE Indicator Fluid only

POISON

Contains chromous chloride, zinc chloride, and hydrochloric acid.

ANTIDOTE

External - Flood with water, then treat affected area with baking soda (sodium bicarbonate).
Internal - Induce vomiting. Administer milk or white of eggs. C mbat collapse.
Eyes - Flush with plenty of water for at least 15 minutes.

CALL PHYSICIAN

3.0 BASIC FYRITE OPERATION PERCENT CO_2 AND O_2

Four basic steps are required when making an analysis, many being common to both CO_2 and O_2 FYRITE.

FYRITE MODEL CO_2 (Red Fluid)	FYRITE MODEL O_2 (Blue Fluid)
(a) Vent and adjust scale zero.	(a) Vent and adjust scale zero.
(b) Pump sample into FYRITE.	(b) Pump sample into FYRITE.
(c) Absorb CO_2 from sample.	(c) Absorb O_2 from sample.
(d) Read % CO_2 on scale.	(d) Read % O_2 on scale.

NOTE: TO PREVENT WARMING OF FYRITE FLUID DURING ANAL YSIS, HOLD FYRITE BY THE FINS ONLY.

CO_2 FYRITE OPERATION (RED FLUID)

1. Hold FYRITE upright (Fig. 2) and away from face. Depress Plunger Valve (momentarily) to vent FYRITE, and release.

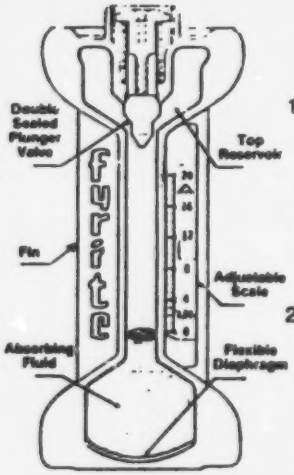


Figure 1

2. Invert FYRITE (Fig. 3) Hold at slight angle to drain fluid into top reservoir.

3. Turn upright. Hold FYRITE at 45° angle (Fig. 4) momentarily to allow fluid droplet drainage into bottom reservoir.

Figure 2

4. Hold FYRITE in upright (Fig.2) position and away from face. Depress Plunger Valve (momentarily), and release.

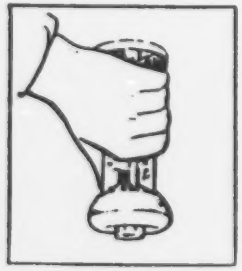


Figure 3

O_2 FYRITE OPERATION (BLUE FLUID)

1. Hold FYRITE upright (Fig. 2) and away from face. Depress Plunger Valve (momentarily) to vent FYRITE, and release.

2. Invert FYRITE (Fig. 3) to absorb O_2 (which is drawn into FYRITE whenever Plunger Valve is depressed). Hold at slight angle to drain fluid into top reservoir.

3. Turn upright. Hold FYRITE at 45° angle to drain fluid into bottom reservoir. Turn upright. Repeat sequence of steps 1, 2 and 3 twice until fluid level does not drop more than ½% when Plunger Valve is depressed. Turn upright. Hold FYRITE at 45° angle (Fig. 4) momentarily until excess fluid droplets have been drained from inside surfaces.

4. Hold FYRITE in upright (Fig. 2) position and away from face. Note fluid level in column. Depress Plunger Valve (momentarily), and release.

CO_2 FYRITE OPERATION (RED FLUID)

5. Holding FYRITE upright (Fig. 5) loosen locknut at rear of scale. Slide scale until top of fluid column lines up with zero on scale. (Fig. 5A). Tighten scale locknut.

Figure 4

NOTE: WHEN SETTING SCALE ZERO, HOLD FYRITE VERTICALLY AS SHOWN AND LEVEL WITH EYES WHILE SIGHTING ACROSS SCALE TO TOP OF FLUID COLUMN.

Figure 5

6. To pump gas sample into FYRITE (Fig. 6), insert open end of metal sampling tube into area bearing gas for analysis. Hold FYRITE in upright position and place sampling assembly rubber connector tip over the Plunger Valve.

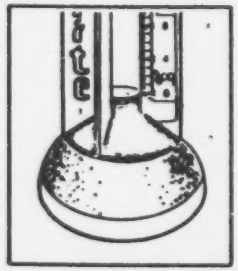


Figure 5A

Depress Plunger Valve firmly with connector tip.

Pump sample by squeezing and releasing aspirator bulb 18 times. during 18th bulb squeeze (with bulb held deflated) release connector tip and Plunger Valve.

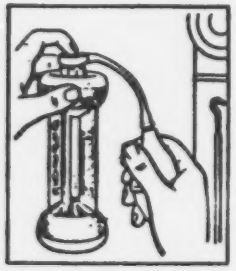


Figure 6

O_2 FYRITE OPERATION (BLUE FLUID)

5. Holding FYRITE upright (Fig. 5), loosen locknut at rear of scale. Slide scale until top of fluid column lines up with zero line on scale. (Fig. 5A). Tighten scale locknut.

NOTE: WHEN SETTING SCALE ZERO, HOLD FYRITE VERTICALLY AS SHOWN AND LEVEL WITH EYES WHILE SIGHTING ACROSS SCALE TO TOP OF FLUID COLUMN.

6. To pump gas sample into FYRITE (Fig. 6), insert open end of metal sampling tube into area bearing gas for analysis. Hold FYRITE in upright position and place sampling assembly rubber connector tip over the Plunger Valve.

Depress Plunger Valve firmly with connector tip.

Pump sample by squeezing and releasing aspirator bulb 18 times. During 18th bulb squeeze (with bulb held deflated) release connector tip and Plunger Valve.

CO_2 FYRITE OPERATION (RED FLUID)

7. Absorb sample gas into FYRITE by inverting until fluid drains into top reservoir (Fig. 7), then turn upright (Fig.8) to drain fluid into bottom reservoir. Repeat this step once.

Figure 7

8. Hold FYRITE at 45° angle (Fig. 9) momentarily to allow fluid droplets to drain into bottom reservoir.

Figure 8

9. With FYRITE held upright (Fig. 10), permit fluid in column to stabilize a few seconds, then immediately read % carbon dioxide on scale at point corresponding to top of fluid column.

Figure 9

O_2 FYRITE OPERATION (BLUE FLUID)

7. Absorb sample gas into FYRITE fluid by inverting until fluid drains into top reservoir (Fig. 7), then turn upright (Fig. 8) to drain fluid into bottom reservoir. Repeat this step three (3) more times (four complete inversions total).

8. Hold FYRITE at 45° angle (Fig. 9) momentarily to allow fluid droplets to drain into bottom reservoir.

9. With FYRITE held upright (Fig. 10), permit fluid in column to stabilize a few seconds, then immediately read % oxygen on scale at the point corresponding to top of fluid column.

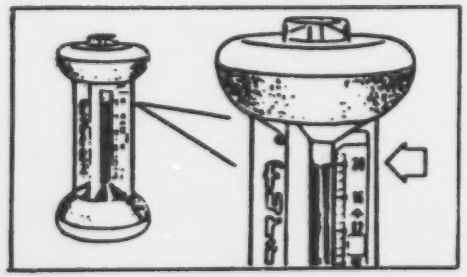


Figure 10

10. This step completes CO_2 or O_2 FYRITE gas sample analysis. A few points to remember when reading the FYRITE.

(a) FYRITE accuracy is within + ½% CO_2 or O_2 compared to actual value.

(b) Always handle FYRITE by the fins to ensure body heat is not absorbed by the fluid.

(c) A delay in reading of 5 or 10 seconds may decrease accuracy of reading slightly but longer delays may cause substantial error.

(d) The FYRITE is calibrated to indicate on a "dry" basis for flue gas samples which are normally fully saturated with moisture. Failure to artifically moisten wool packing in Filter Saturator Tube when actual sample is not fully saturated will cause FYRITE to read slightly low.

Therefore make certain wool packing in Filter Saturator Tube is sufficiently moistened with water for accurate results on non-flue gases. Avoid excessive moisture which can be drawn into the Aspirator Bulb and forced into the FYRITE during sampling.

(e) **CAUTION: Never depress plunger valve to vent Fyrite in the inverted position. This will cause fluid spill which is corrosive and contains poisonous elements. In the event of a spill, read instructions in Section 2.2 Fyrite fluid handling precautions.**

3.1 Determining CO_2 and O_2 FYRITE Fluid Strength

FYRITE Fluid strength can be conveniently checked immediately after the first sample reading.

Without venting, repeat the absorbing operations (Steps 7 through 9) by inverting FYRITE again and positioning upright until all fluid drains to the bottom reservoir. Observe scale reading. An increase of more than ½% CO_2 or O_2 in second reading as compared to the first indicates a need for fluid replacement.

3.2 Operating Precautions to Ensure Maximum Accuracy when Reading FYRITE

Locate top of fluid column (refer to Fig. 11).

The surface at the top of the fluid column in the small, center bore will be dish-shaped as shown in Fig. 11. Either the high or low point of this dish-shaped surface may be used to locate top of fluid column providing the same point is always used both for setting scale zero and reading percent CO_2 or O_2. Obviously, using high point for one operation and low point for the other will cause error.

Best practice is to use high point of this fluid surface just at the small center bore wall. In setting scale zero or reading percent CO_2 or O_2 hold FYRITE vertically and level with eyes and sight across scale to top of fluid column.

3.2.1 Draining Fluid Droplets

For maximum accuracy, it is important to form the habit of following a standard procedure in this operation and to use the same procedure both before adjusting scale zero and before reading percent CO_2 or O_2.

3.3 FYRITE Temperature

The FYRITE temperature should be at or close to the temperature of the working environment where the analysis is being made and should not be subject to sudden temperature changes. If FYRITE is carried from cooler to warmer location or vice versa, expose FYRITE to new temperature condition to permit uniform temperature stabilization. Usually 15 or 20 minutes will suffice except when extreme temperature variations are involved.

Temperature stabilization can also be accelerated by inverting FYRITE frequently.

3.3.1 Temperature of Gas Sample

The gas sample as it enters FYRITE should be cooled (or warmed if sampling cool gases) to same (ambient) temperature as the FYRITE.

Capacity of Standard Aspirator Bulb and Sampling Assembly Code 11-7029 to cool the gas sample is sufficient if temperature of gas being sampled does not exceed 850°F (454°C), even where a large number of consecutive samples are required if there is an interval of not less than five (5) minutes between samples.

FYRITE indicators operate over a wide teperature range. They may be exposed to ambient temperatures from -30° to 150°F (-34° to 66°C). Gases up to 850°F (454°C) may be tested with Standard Aspirator Sampling Assembly Code 11-7029. Special sampling equipment for high temperatures and unsaturated gas samples are listed in Section 7.2. FYRITE Sampling Assemblies.

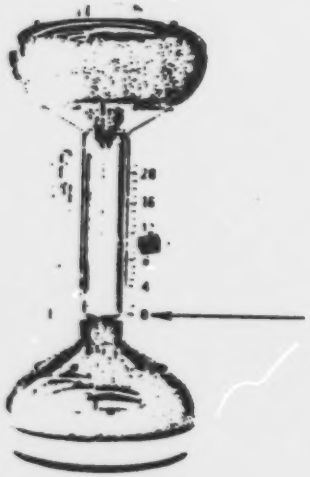


Figure 11 Locating Top of Fluid Column.

4.0 PRINCIPLE OF OPERATION (Refer to Figures 12, 13, and 14.)

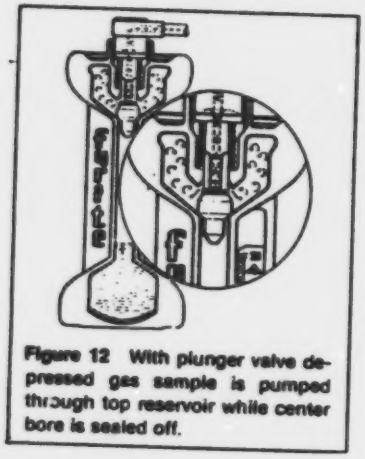


Figure 12 With plunger valve depressed gas sample is pumped through top reservoir while center bore is sealed off.

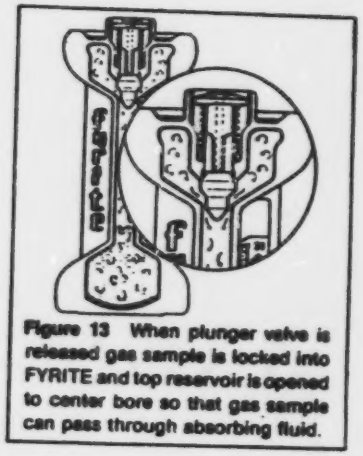


Figure 13 When plunger valve is released gas sample is locked into FYRITE and top reservoir is opened to center bore so that gas sample can pass through absorbing fluid.

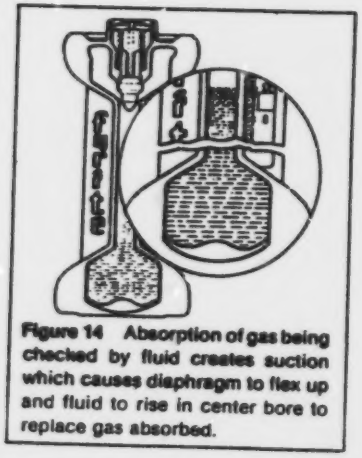


Figure 14 Absorption of gas being checked by fluid creates suction which causes diaphragm to flex up and fluid to rise in center bore to replace gas absorbed.

To make a test with the FYRITE, the metal Sampling Tube at one end of Sampling Assembly Hose is inserted into the gas to be analyzed. The rubber Connector Plug at the other end of the Rubber Hose is then firmly pressed down on the spring-loaded Valve of the instrument (See Figure 12). This simultaneously opens a passage into the Top Reservoir and seals off the center bore.

Next, a sample of the gas is pumped into the Top Reservoir by squeezing the rubber Aspirator Bulb. At least 18 bulb squeezes are required to assure that the rubber Sampling Hose and the Top Reservoir of the FYRITE are thoroughly purged of the previously analyzed sample. During the 18th Aspirator Bulb squeeze and immediately before releasing Bulb, the finger is lifted from the Connector Plug which automatically returns the Plunger Valve to upper position against its top seat.

Refer to Figure 13, with the Valve in this position, the final 60 cc. of the gas sample is locked into the FYRITE and the Top Reservoir is opened to the center bore so that the gas sample can pass to the absorbing fluid.

The FYRITE is then inverted, forcing the gas sample to bubble through the absorbing solution which absorbs either CO_2 or O_2 depending on the type FYRITE in use.

Refer to Figure 14. The instrument is then turned and held upright. Absorption of the CO_2 or O_2 by the absorbing fluid creates a suction which causes the Diaphragm at the bottom to flex upward permitting the level of the absorbing fluid to rise in the center tube an amount proportional to the gas absorbed. The scale indication corresponding to the top of the fluid column is then read as percentage of gas absorbed by the FYRITE fluid.

5.0 APPLICATION INFORMATION

FYRITE Analyzers are available for either Carbon Dioxide or Oxygen analysis, and each of these models is made in the three scale ranges shown in Section 5.3.

All six instruments are similar in appearance and size, but they differ in important construction details, as well as in absorbing fluids.

5.1 FYRITE Absorbing Fluid

FYRITE absorbing fluid is selective in the chemical absorption of carbon dioxide or oxygen respectively. Therefore, the FYRITE's accuracy is well within the range required for industrial and professional applications, and does not depend upon complicated sequential test procedures. Furthermore, the FYRITE readings are unaffected by the presence of most background gases in the sample.

The appearance of a dark red fluid floating on top of CO_2 FYRITE solution is entirely normal. The darker fluid consists of a small amount of material added to prevent excessive foaming at the meniscus and improves readability.

5.1.1 FYRITE Refill Fluid (Storage Life, etc.)

FYRITE refill bottles should be stored at room temperature (70° F, 21° C) in the carton provided and placed in use within one year.

NOTE: BEFORE OPENING REFILL BOTTLE, READ THE LABEL AND MAKE CERTAIN TO OBSERVE ALL PRECAUTIONS.

FYRITE CO_2 refill fluid may develop a white insoluble precipitate upon aging. The precipitate does not affect fluid performance in any way, but if present, should be filtered out to prevent adherence to internal surfaces of the FYRITE.

To filter, place a clean piece of thin cloth or netting loosely over the open CO_2 FYRITE and slowly pour refill contents into top reservoir. Before disposing of cloth, rinse thoroughly with water. FYRITE fluid is corrosive.

FYRITE O_2 refill fluid reacts very rapidly with oxygen in air. Oxidation of absorbant can be prevented by purging the FYRITE body with Nitrogen, natural gas or other oxygen-free gas, just before filling, and by maintaining a stream of this gas around mouth of the bottle while its contents are emptied into the FYRITE.

5.2 FYRITE Operating Temperature Range

The FYRITE indicators operate over a wide range. They may be exposed to ambient temperatures from -30° to 150° F. (-34° to 66° C).

Gases up to 850° F (454° C) may be tested with standard aspirator sampling equipment. (Code 11-7029).

Special sampling equipment to reduce high combustion gas temperatures (2000° F, 1093° C) to usable FYRITE temperature (ambient) and assemblies with extra large saturators for dry gas sampling are listed in Section 7.2, FYRITE Sampling Assemblies.

NOTE: REMEMBER: FOR MOST ACCURATE RESULTS, THE FYRITE MUST BE AT TEMPERATURE EQUILIBRIUM WITH ITS SURROUNDINGS (AMBIENT TEMPERATURE) AND THE INCOMING GAS SAMPLE AT THE SAME TEMPERATURE AS THE FYRITE.

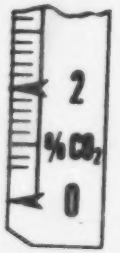
5.3 Typical FYRITE Applications

Listed below are six Models of FYRITE Indicators and three Aspirator Sampling Assemblies with code numbers identifying their application.

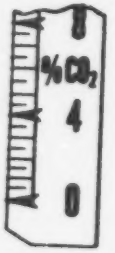
		Bacharach Code Number		
For Testing	Scale Range	FYRITE	Aspirator Sampling Assy.	Refill Fluid
Carbon Dioxide	0 - 7.6%	11-7042	11-7039	10-5100
	0 - 20%	11-7032	11-7029	10-5057
	0 - 60%	11-7034	11-7029	10-5057
Oxygen	0 - 7.6%	11-7044	11-7039	10-5103
	0 - 21%	11-7036	11-7029	10-5060
	0 - 60%	11-7038	11-7029	10-5060

TYPICAL APPLICATIONS WITH FULL SIZE SECTIONS OF FYRITE SCALES

0-7.8% CO_2 or O_2
CO_2 tests of controlled atmospheres in fruit, vegetable, and meat storage rooms. Oxygen determination in flammable gases. Oxygen tests to check atmospheres inerted with nitrogen (silos, fuel tanks, etc.)



0-20% CO_2 0-21% O_2
Flue gas combustion tests, oxygen deficiency tests, and CO_2 tests of heat treating atmospheres. Checking oxygen concentrations in hydrogen-cooled generators and oil-sealed inert gas transformers.



0-60% CO_2 or O_2
Checking CO_2 in inert gas blankets in tankers and barges carrying gasoline and other combustibles. CO_2 tests on lime kilns. Checking CO_2 in sewage plant digesters. Oxygen tests in connection with oxygen and gas anesthesiology.

5.4 CO_2 FYRITE ONLY Combustion Testing

5.4.1 Percent CO_2 Shows Volume of Excess Air (Refer to Figure 15)

For any given fuel, theoretical maximum percent CO_2 (Ultimate CO_2) would be produced when exactly enough air (but no excess air whatsoever) is supplied to burn all of the fuel. As increasing amounts of excess air are supplied, percentage CO_2 naturally decreases from theoretical Ultimate CO_2 due to the diluting effect of excess air.

Thus measuring percent CO_2 is also a method of indicating excess air to ensure that enough is supplied to permit clean combustion without adding so much that combustion efficiency is unnecessarily decreased.

5.4.2 Too Much Excess Air Means Inefficient Combustion

Excess combustion air is heated and carries some of this heat to the flue where it is wasted. The FYRITE CO_2 Analyzer is used to adjust combustion excess air to a minimum (maximum CO_2) which will permit clean efficient combustion.

Calculation of combustion efficiency is possible (assuming complete combustion) if percentage of CO_2 and net temperature of combustion products are known.

5.4.3 What Is Proper CO_2 Value?

Proper CO_2 is that which will ensure complete, clean combustion with some safety margin for variations in fuel, draft, atmospheric conditions, and mechanical wear.

Consult manufacturer of heating equipment for specific recommendations. Generally accepted values for good combustion practice in residential furnaces and boilers when firing the following fuels are:

Natural Gas ..... 8 to 9.5% CO_2
No. 2 Oil ..... 10 to 12.5% CO_2

However these are only guidelines and in all cases recommendations of the equipment or fuel supplier would also include recommendations for allowable smoke (oil firing) or combustibles (gas firing) which are undesirable combustion by-products.

5.4.4 How To Calculate Combustion Efficiency

Measure percent CO_2 in flue gases with FYRITE. Then measure flue gas temperature with a suitable thermometer (TEMPOINT) at the same sampling point. Deduct temperature of basement or combustion air supplied from measured flue gas temperature to obtain net flue gas temperature. Use Bacharach FIRE EFFICIENCY FINDER to calculate combustion efficiency. Instructions for using the FIRE EFFICIENCY FINDER are printed on the face of this slide rule calculator.

5.5 O_2 FYRITE ONLY Combustion Testing

5.5.1 Percent O_2 Shows Volume of Excess Combustion Air (Refer to Figure 15)

All fuels require some excess air (in addition to air theoretically required to burn the fuel) to ensure clean, complete combustion. As amount of this excess air increases, the percentage of O_2 in combustion products increase.

5.5.2 Too Much Excess Air Means Inefficient Combustion

Excess combustion air is heated and carries some of this heat to the flue where it is wasted. The FYRITE O_2 analyzer is used when adjusting combustion air to minimum excess air (miminum O_2) which will permit clean, efficient combustion.

5.5.3 What is Proper O_2 Value?

Proper O_2 content for any fuel fired is the lowest O_2 value which will ensure complete, clean combustion with adequate safety margin for variations in fuel, draft, atmospheric conditions, and mechanical wear. Consult manufacturer of heating equipment or local authorities for specific recommendations. Figure 15 illustrates the relationship between O_2 excess air and oxygen for gas and oil.

For guidance, it should be added that modern boilers are capable of 80% or greater combustion efficiency. Rough guidelines for setting conventional power burners are 10-15% excess air for natural gas and 15-20% excess air for oil, with little or no smoke and carbon monoxide formation.

5.5.4 Measuring O_2 In Addition to CO_2

Figure 16 illustrates why it is good practice to measure oxygen, in addition to carbon dioxide, when firing gaseous fuels. Note that the same O_2 reading can be obtained on both sides of the stoichiometric (or perfect) mixture. Carbon dioxide alone cannot define proper excess air operation for gaseous fuels.

A check must also be made for the presence of oxygen which confirms operation with excess air. Gaseous fuels should also be checked for presence of carbon monoxide (CO) in the flue gases and adjusted for either "no CO" or to conform to applicable safety regulations.

5.5.5 Where is Percent CO_2 or O_2 Measured? (Refer to Figure 17)

For residential and most commercial and industrial combustion units, percent CO_2 or O_2 is measured by analyzing gas sample obtained through a ¼ inch diameter hole located between the flue outlet (breeching) and any mechanical opening in the flue such as the barometric draft regulator or draft diverter. Best practice is to locate sampling hole at least six inches upstream from such flue openings. The metal FYRITE Sampling Tube should extend at least 2½ inches into the flue gases.

For larger installations, consult manufacturer of combustion equipment for special instructions regarding sampling point, special sampling tube required, or advice on averaging readings.

Residential gas furnaces with built-in draft diverter (gas designed) will require the FYRITE metal Sampling Tube to be inserted as illustrated in Figure 17 to avoid dilution of flue gas sample.

Additional information on residential furnace combustion testing may be obtained from the following Bacharach publications:

Bulletin 4006 — Gas Burner Combustion Testing
Bulletin 4011 — Oil Burner Combustion Testing

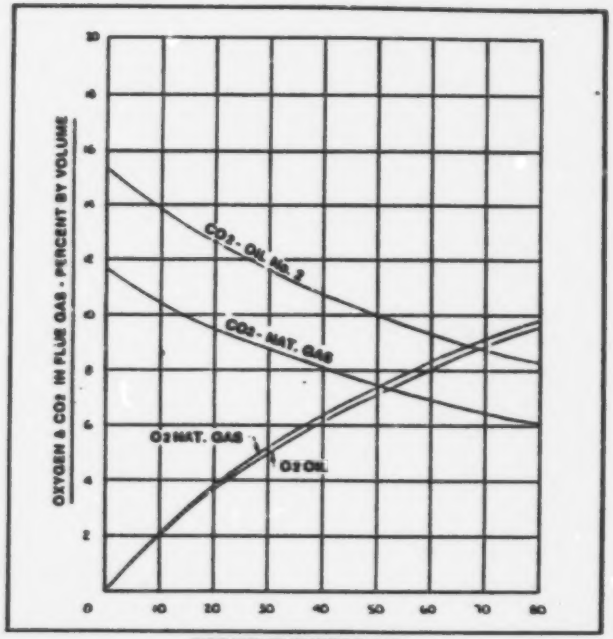


Figure 15 Relation Between Oxygen, CO_2 & Excess Air in Flue Gases For Natural Gas & Fuel Oil.

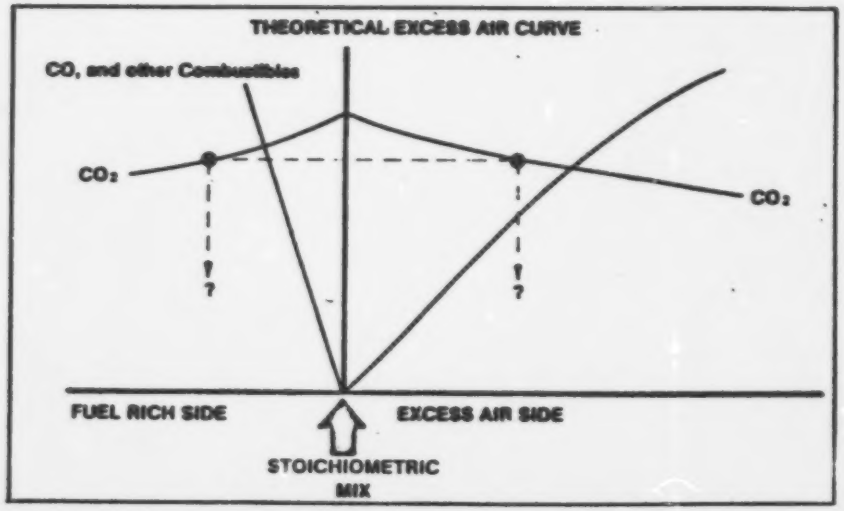


Figure 16 CO_2 Measurements Alone Do Not Determine Combustion Air Setting When Firing Gaseous Fuels.

5.6 Background Gases Affecting FYRITE Readings

As a rule of thumb, background gases/vapors may be present in concentrations up to ½% by volume (5000 ppm) before they present a significant interference problem to the CO_2 or O_2 FYRITE (20/21% ranges)

An exception exists with the action of ammonia on the Oxygen FYRITE Fluid. Ammonia neutralizes the acidic solution of chromous chloride, and therefore use of the O_2 FYRITE with even trace amounts of ammonia in the backgrounds is not advised unless suitable filters are used.

Inert gases, even in concentrations approaching 100% by volume, do not interfere with either the CO_2 or O_2 FYRITE. In general, interferences can be of a chemical (chemical reaction initiated) or a mechanical nature, with resultant error, but are also given up by the solution when the sample no longer contains the interfering substance. They can therefore be compensated for by saturating the FYRITE solution with samples containing the mechanical interferent as long as the background stays reasonably constant. Usually 3 or 4 tests are sufficient to saturate FYRITE solution with the mechanical interferent in question.

TYPICAL INTERFERENCE (CO_2 FYRITE)	TYPE OF INTERFERENCE	APPROXIMATE EFFECT
All Acid Gases (SO_2, H_2S, Hydrocyanic Acid, Cyanogen, etc).	Chemical	1:1

TYPICAL INTERFERENCE (O_2 FYRITE)	TYPE OF INTERFERENCE	APPROXIMATE EFFECT
Acetone	Chemical	1:1
Acetylene and other unsaturated hydrocarbons	Chemical	1:1
CO_2	Mechanical 20% CO_2 background can be zeroed out in 3 to 4 tests if background remains constant.	Can be zeroed out up to approximately 30% CO_2 background.
Ammonia	Chemical	Ammonia neutralizes O_2 FYRITE solution and instrument use on this background is not advised unless suitable filters are used.
Nitrous Oxide (N_2O)	Mechanical	— — — —

Figure 17 Checking CO_2 of gas designed furnace (sampling tube inserted through draft diverter; flue gas temperature test can be made at same point).

5.7 General FYRITE Applications

It is only possible to specify a few general rules for such applications. Where possible, sample should be obtained at a point where the gases are well mixed to a uniform composition. Where this is impossible; it will be necessary to average a number of measurements taken at different locations to obtain representative average. Where gases being sampled are not saturated with moisture (many non-combustible applications), it is very important to maintain the wool packing of Filter Saturator Tube in a moist condition.

NOTE: THE FYRITE IS CALIBRATED TO ANALYZE GASES WHICH ARE NORMALLY SATURATED WITH MOISTURE. FAILURE TO MOISTEN WOOL PACKING IN FILTER SATURATOR TUBE WITH WATER WILL CAUSE FYRITE TO INDICATE SLIGHTLY LOWER THAN ACTUAL GAS CONCENTRATION.

Where special length sampling lines are required, add one more bulb squeeze to the 18 required with standard Sampling Assembly for each additional 3 cubic inches (50cc) volume of special sampling line.

EXAMPLE: For each 6 ft. of 3/16 inch (I.D.) additional length of sampling line, add one more bulb squeeze.

If it is necessary to trap a sample over water for later analysis, a minimum of 900 cubic centimeters of sample will be required. If sample is trapped over water, it is good practice to use 10 to 15% NaCl (table salt) in the water to minimize absorption of CO_2 or O_2 by water.

Trapping a sample over mercury will eliminate any possible error due to absorption of CO_2 or O_2.

6.0 FYRITE MAINTENANCE

6.1 Increasing FYRITE Fluid to Proper Level

With FYRITE in vertical position, top of fluid column should not be less than ⅛ inch or more than ¾ inch above the bottom of the small, center FYRITE bore. Be sure to depress Plunger Valve to vent FYRITE to atmosphere before checking fluid level. To raise fluid level, add clean water. Refer to Figure 18. Hold FYRITE upright and cover hole in center of Plunger Valve with finger.

Add clean water, a few drops at a time (dripping water faucet is convenient) into space around Plunger Valve. Work Plunger Valve up and down several times. Repeat process until fluid is at proper level.

6.1.1 Decreasing FYRITE Fluid to Proper Level

Refer to Figure 19. To remove excess fluid, insert small diameter glass tube into FYRITE fluid through the small center FYRITE bore (with Top Cap Assembly removed). Seal open end of glass tube with finger and dip out fluid with glass tube until FYRITE fluid is at proper level.

Avoid unnecessary exposure of O_2 fluid to air since it will rapidly absorb O_2 and become exhausted.

6.2 Checking FYRITE Fluid Strength

6.2.1 CO_2 FYRITE Fluid Only

Fresh FYRITE fluid will absorb all CO_2 from more than 350 samples containing 10 percent CO_2.

Where it is desirable to check fluid strength before taking FYRITE to the test location where it will be used, or when a questionable (low) FYRITE reading is obtained the instrument may be tested on any sample of CO_2. Exhaled breath (containing approximately 4% CO_2) is often most convenient.

Disconnect the rubber bushing and Sampling Hose Assembly from the Filter Saturator Tube. Place the rubber connector tip over the Plunger Valve and depress Plunger Valve down firmly with rubber connector tip. Take a deep breath, hold for 3 or 4 seconds and exhale at a steady rate into the rubber bushing end of the Sampling Hose Assembly. Simultaneously squeeze the Aspirator Bulb several times while exhaling breath. Release rubber connector tip from Plunger Valve while still exhaling breath. Perform steps outlined below to absorb exhaled breath into FYRITE fluid.

1. Absorb sample gas into FYRITE by inverting until fluid drains into top reservoir, then turn upright to drain fluid into bottom reservoir. Repeat this step once more (two complete inversions total).
2. Hold FYRITE at 45° angle momentarily to allow fluid droplets to drain into bottom reservoir.
3. With FYRITE held upright, permit fluid in column to stabilize a few seconds, then immediately read, % carbon dioxide on scale at point corresponding to top of fluid column.

To check CO_2 FYRITE fluid strength — DO NOT VENT FYRITE but reabsorb sample gas by inverting and turning upright. Repeat this

Figure 18 Increasing FYRITE Fluid to Proper Level.

Figure 19 Decreasing FYRITE Fluid to Proper Level.

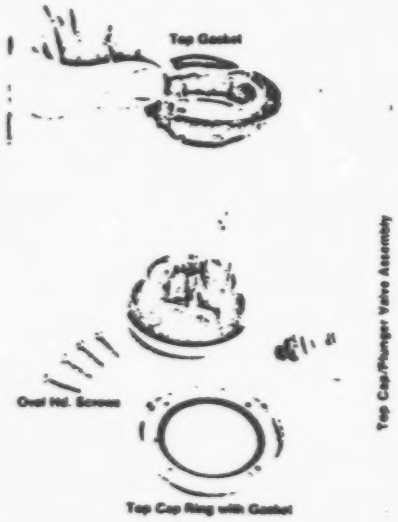


Figure 20 Removing Top Gasket.

Figure 21 Flushing FYRITE with a stream of O_2-free, inert gas.

by more than ½ percent CO_2 as compared to initial reading; replace fluid.

Formation of a frothy, persistent foam on FYRITE fluid also indicates need for fluid replacement. A few "beads" or small air bubbles floating near the small center bore wall is not considered foaming. FYRITE fluid may be colored for ease in readings. Color has no bearing on fluid strength or ability to absorb CO_2.

Cloudy fluid or small flakes of solid material in fluid do not necessarily mean CO_2 fluid is exhausted. Precipitate may form in CO_2 Refill Bottles due to extended storage, and can be filtered through cheese cloth or other screen like material when refilling FYRITE.

NOTE: IF COMPRESSED GAS STANDARDS ARE USED TO CHECK FYRITE ACCURACY DON'T FORGET TO SATURATE FILTER SATURATOR WOOL PACKING AS SUCH GAS STANDARDS ARE SUPPLIED "BONE DRY".

6.2.2 O_2 FYRITE Fluid Only

Fresh FYRITE fluid will absorb all O_2 from approximately 100 samples containing 10 percent O_2. After completing test (as outlined in Sec. 3.0 Steps 1 through 9) O_2 FYRITE Fluid strength can be checked by performing steps outlined below:

1. DO NOT VENT FYRITE, but reabsorb sample gas into FYRITE by inverting until fluid drains into top reservoir, then turn upright to drain fluid into bottom reservoir. Repeat this step three (3) more times (four complete inversions total).
2. Hold FYRITE at 45° angle momentarily to allow fluid droplets to drain into bottom reservoir.
3. With FYRITE held upright, permit fluid in column to stabilize a few seconds, then immediately read, % oxygen on scale at the point corresponding to top of fluid column. If reading increases by more than ½ percent O_2 as compared to the initial reading, replace fluid.

Where it is desirable to check fluid strength before taking FYRITE to a location where it will be used, it can be conveniently tested on a sample of atmospheric air which contains 20.9 percent O_2.

NOTE: MAKE CERTAIN WOOL IN FILTER SATURATOR TUBE IS MOISTENED WITH WATER WHEN USING FYRITE IN A NON-COMBUSTIBLE APPLICATION WHERE GAS SAMPLE IS NOT FULLY SATURATED WITH WATER VAPOR.

Formation of a frothy, persistent foam on FYRITE fluid also indicates need for fluid replacement. A few "beads" or small air bubbles floating near the small center bore wall is not considered foaming. Color of FYRITE O_2 (blue) fluid is not an index of ability to absorb oxygen although towards the end of fluid life, a greenish cast can be detected.

NOTE: IF COMPRESSED GAS STANDARDS ARE USED TO CHECK FYRITE ACCURACY, DON'T FORGET TO SATURATE FILTER SATURATOR WOOL PACKING AS SUCH GAS STANDARDS ARE SUPPLIED "BONE DRY".

6.3 Replacing FYRITE Fluid (Refer to Figures 20, 21, and 22)

CAUTION: ALWAYS CHANGE FYRITE FLUID IN IMMEDIATE VICINITY OF SINK WITH RUNNING WATER AVAILABLE AS SHOWN IN FIGURE 18, BECAUSE OF THE CORROSIVE EFFECT OF FYRITE FLUID.

Remove 4 screws, metal Top Cap Ring, plastic Top Cap Assembly and Top Gasket.

Drain old fluid from FYRITE and rinse all parts in clean, lukewarm water.

NOTE: FYRITE FLUID IS CORROSIVE TO SKIN, CLOTHING, SOME METALS, AND PAINTED AND LACQUERED SURFACES.

When draining into porcelain sink, keep water faucet turned on while draining and for about ½ minute afterwards.

NOTE: EXAMINE TOP GASKET FOR WARPAGE, IF DISTORTED AS SHOWN IN FIGURE 22, REPLACE GASKET WITH CODE 11-0143 BEFORE PROCEEDING.

Drain all parts of excess water. Stand FYRITE Body upright to center replacement Top Gasket in recess provided in top flange of body.

O_2 FYRITE Only: Before adding fluid, flush FYRITE with a stream of O_2-free, inert gas (Figure 21) or be prompt in reassembling Top Cap to prevent excessive fluid contact with air.

Uncap FYRITE Fluid bottle, make certain to observe precautions on the label then immediately add O_2 Refill Fluid to top Reservoir Volume of FYRITE. Immediately install plastic Top Cap Assembly and metal Top Cap Ring without delay.

CO_2 FYRITE Only: Uncap CO_2 Refill Bottle and pour entire contents into FYRITE Reinstall plastic Top Cap Assembly and metal Top Cap Ring.

CO_2 / O_2 FYRITES: Make certain that Top Cap ring Gasket (11-0136) is in place between metal Top Cap Ring and plastic Top Cap. Draw the 4 machine screws down with light screwdriver force.

Then, going from one screw to the next, draw down ¼ turn until all are firmly tightened.

Avoid excessive force in tightening which may damage plastic parts.

6.4 Inspection of FYRITE for Fluid Leakage

Gradual loss of fluid, moisture or dried encrustation around Plunger Valve does not indicate fluid leakage.

Gas enters and leaves FYRITE during sampling with considerable velocity and some fluid vapor is carried out during normal sampling. To check Top Assembly for fluid leakage in upright position, depress Plunger Valve and release.

Note the scale reading at top of fluid column, stand FYRITE upside down overnight in glass or porcelain test dish (See Figure 23). Then, return FYRITE to upright position and, after allowing 5 minutes for drainage, depress and release Plunger Valve. Leakage will be evidenced by lower scale reading. Extreme leakage will be apparent by presence of fluid in test dish.

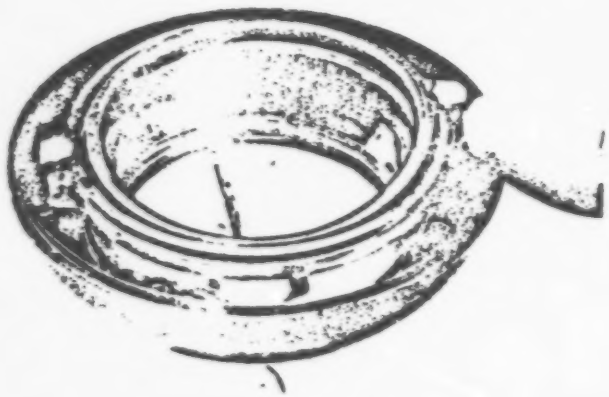


Figure 22 Examining Top Gasket for Warpage.

Figure 23 FYRITE inverted in test dish (overnight) for leakage check.

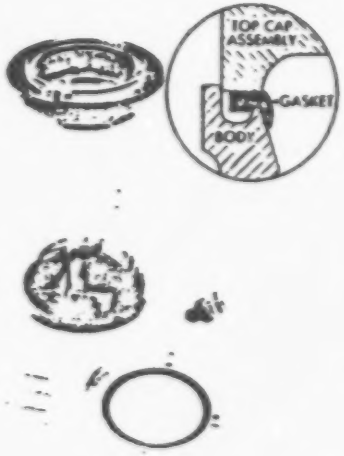


Figure 24 Top Gasket Properly Centered in top flange of FYRITE Body.

Follow the same procedure to check fluid leakage from Bottom Cap Assembly with FYRITE stood overnight in the upright position.

When leakage is proven, examine plastic and rubber parts for deterioration to determine replacement parts necessary for repair, or drain instrument and return if factory service or repair is desired.

6.5 Cleaning FYRITE

Use only soapy lukewarm water if cleaning is required (lukewarm water is usually sufficient).

NOTE: USE OF GASOLINE, NAPTHA, CARBON TETRACHLORIDE OR ANY OTHER ORGANIC SOLVENT OR OILS WILL DESTROY PLASTIC AND RUBBER PARTS.

6.6 Replacing FYRITE Plastic and Rubber Parts (Refer to Illustrated Parts Breakout Section 7.0 and Figure 24)

Replace plastic parts when cracked or crazed in location exposed to fluid and rubber parts when badly swollen, warped or showing other evidence of deterioration.

In replacing Top Gasket, make certain it is properly centered in the recess provided in top flange of FYRITE Body (See Figure 24). When installing plastic Top Cap Assembly, be sure that Assembly is centered on Top Gasket.

To remove Top Cap Assembly or replace Top Cap, Plunger Valve, or Plunger Tip Gasket, use the procedure as outlined in Section 6.3.

When replacing Plunger Tip Gasket, simply depress Plunger Valve against its spring limit and strip old Tip Gasket from the end of Plunger Valve.

Before assembling new Gasket, wet inside surface of Tip Gasket, then force it over the end of Plunger Valve (after depressing Plunger Valve against the spring limit).

Make certain that new Tip Gasket is seated uniformly against the mating surface in plastic Top Cap.

To replace Diaphragm, stand FYRITE upside down, remove 4 screws and metal Bottom Cap.

Refer to Figure 25A. Remove old Diaphragm and center new replacement with the letter (N) facing inward into FYRITE Bottom Cap Recess. Center Bottom Cap Assembly in Body Recess and reinstall 4 screws, observing same precautions in tightening as outlined in Section 6.3.

To replace Body, remove the 4 hex head Bezel screws and 4 Bezels. Install Bezels on new Body.

NOTE: MAKE CERTAIN THE RUBBER BEZEL GASKETS ARE PROPERLY SEATED AND CLAMPED BETWEEN BEZEL AND BODY AS SHOWN IN FIGURE 25.

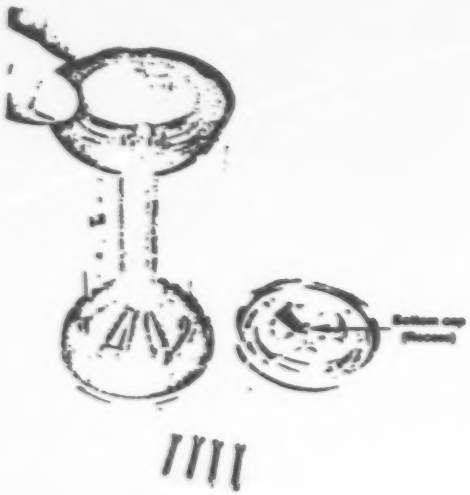


Figure 25A Replacement Diaphragm Properly Installed.

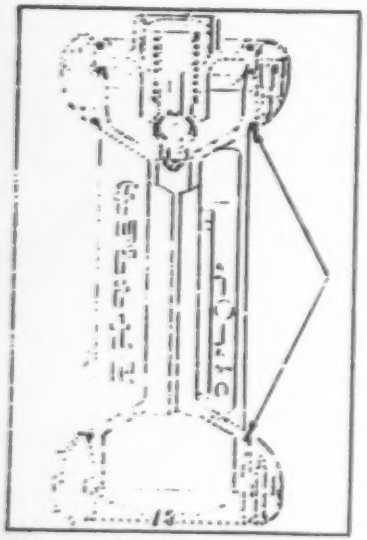


Figure 25 Locating Bezel Rubber Gaskets.

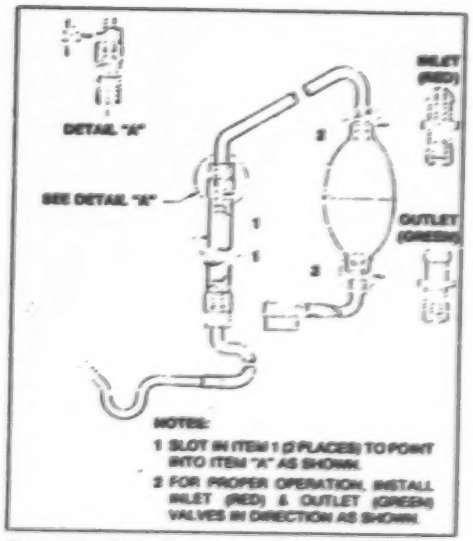

DETAIL "A"
SEE DETAIL "A"
INLET (RED)
OUTLET (GREEN)
NOTES:
1 SLOT IN ITEM 1 (2 PLACES) TO POINT INTO ITEM "A" AS SHOWN.
2 FOR PROPER OPERATION, INSTALL INLET (RED) & OUTLET (GREEN) VALVES IN DIRECTION AS SHOWN.

Figure 26 FYRITE Sampling Assembly; Locating Inlet/Outlet Check Valves.

6.7 Aspirator Bulb - Sampling Assembly (Refer to Figures 26, 27, and 28)

Defective Check Valves or a leaking Sampling Assembly can result in sample loss, or sample dilution with resultant loss of accuracy.

To inspect Sampling Assembly, seal hole in the center of rubber Connector Tip firmly with finger and squeeze Aspirator Bulb (Figure 27). Bulb should remain firm. If Bulb collapses, check Bulb and Hose to Connector Tip for cracks or other source of leakage. Replace defective parts.

If there are no apparent leaks in the Sampling Assembly, replace red Inlet Check Valve. Install as per Figure 26.

Now seal end of metal Sampling Tube with finger, and collapse Aspirator Bulb. (Figure 28). If the Bulb returns to original shape in less than 15 seconds, inspect Hose, Filter Saturator Tube and Metal Sampling Tube for leaks. If none are found, replace the green Outlet Check Valve. Small hole green-coded end of Check Valve fits in Aspirator Bulb and green ring end (large hole) fits in the Hose.

Discard Filter Packing when it becomes dirty or clogged. Push old packing out, and new packing into Filter Saturator Tube with a pencil or small rod.

6.8 Storing FYRITE and Refill Fluid

When not used over periods between tests, store FYRITE and Sampling Assembly in cool, dry place. Prolonged storage, for example, at high temperatures reached in an automobile trunk over Summer is not recommended. When stored unused over Summer, it is good practice to drain old fluid and replace with fresh charge (fluid) when needed in the Fall.

FYRITE Refill Fluid should also be stored in a cool, dry location in the carton provided. A recommended practice is to accumulate stock only sufficient for one year requirement and to use oldest stock first. Fluid can be tested for performance according to Section 6.2.

Use only Bacharach CO_2 or O_2 Fluid Refills for the range FYRITE selected. The Kits below contain three Refill Bottles each.

7% CO_2 range	use 10-5100 Refill Kit
20% and 60% CO_2 range	use 10-5057 Refill Kit
7% O_2 range	use 10-5103 Refill Kit
21% and 60% O_2 range	use 10-5060 Refill Kit

6.9 Replacing Saturator Filter Packing Code 11-0121 (Refer to Figures 29 through 32)

Remove the filter tube nipple and bushing (See Figure 29) from each end of the tube. Use a pencil or similar object to remove packing when it becomes dirty or clogged.

Wrap replacement packing around the hand (See Figure 30). If testing unsaturated gases (most noncombustible applications), saturate packing in water as shown in Figure 31 and wring out excess moisture.

Insert saturated packing using a pencil or small rod into filter tube (See Figure 32), then reassemble nipple and bushing.

Figure 27 Testing Sampling Assembly (Outlet Side) for leaks.

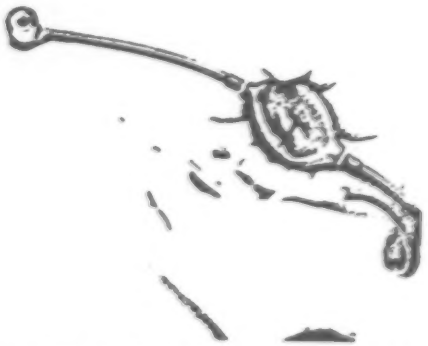


Figure 28 Testing Sampling Assembly (Inlet Side) for leaks.

Figure 29 Removing End Plugs from Saturator Filter Tube.

Figure 30 Wrapping Replacement Filter Material.

Figure 31 Wetting Filter Material then squeezing out excess water.

Figure 32 Installing wetted Filter Material into Saturator Tube.

7.0 ILLUSTRATED PARTS LIST FYRITE CO_2 / O_2 (Refer to Figure 33 FYRITE Parts Breakout

Code No.	Description	Qty.-Req'd.
11-0102	Bezel	4
01-0661	Oval Head Screw	8
11-0110	Bezel Screw	4
11-0109	Bezel Gasket	2
11-0105	Scale Screw	1
02-3690	Scale Screw Nut	1
11-0021	Diaphragm	1
11-0126	Bottom Cap	1
11-0132	Top Cap	1
11-0019	Valve Plunger	1
11-0026	Valve Plunger Spring	1
11-0020	Valve Plunger Gasket	1
11-0136	Top Cap Ring with Gasket	1
11-0143	Top Gasket	1
11-0140	FYRITE Body (All Models except 7.0% CO_2 / O_2)	1
11-0154	FYRITE Body - 7% CO_2 / O_2 only	1
11-0062	Filler 60% FYRITE (Adapter Plug)	1
05-5169	O-Ring Filler (Outer 60%)	1
05-5155	O-Ring Filler (Inner 60%)	1
11-0144	CO_2 Scale 20%	1
11-0415	O_2 Scale 21%	1
11-0147	CO_2 Scale 60%	1
11-0150	O_2 Scale 60%	1
11-0155	CO_2 Scale 7%	1
11-0157	O_2 Scale 7%	1
10-5057	Carton of FYRITE CO_2 Fluid (3 Bottles) 20/60% range Models	1
10-5060	Carton of FYRITE O_2 Fluid (3 Bottles) 21/60% range Models	1
10-5100	Carton of FYRITE CO_2 Fluid (3 Bottles) 7% range Models	1
10-5103	Carton of FYRITE O_2 Fluid (3 Bottles) 7% range Models	1

7.1 FYRITE Illustrated Parts

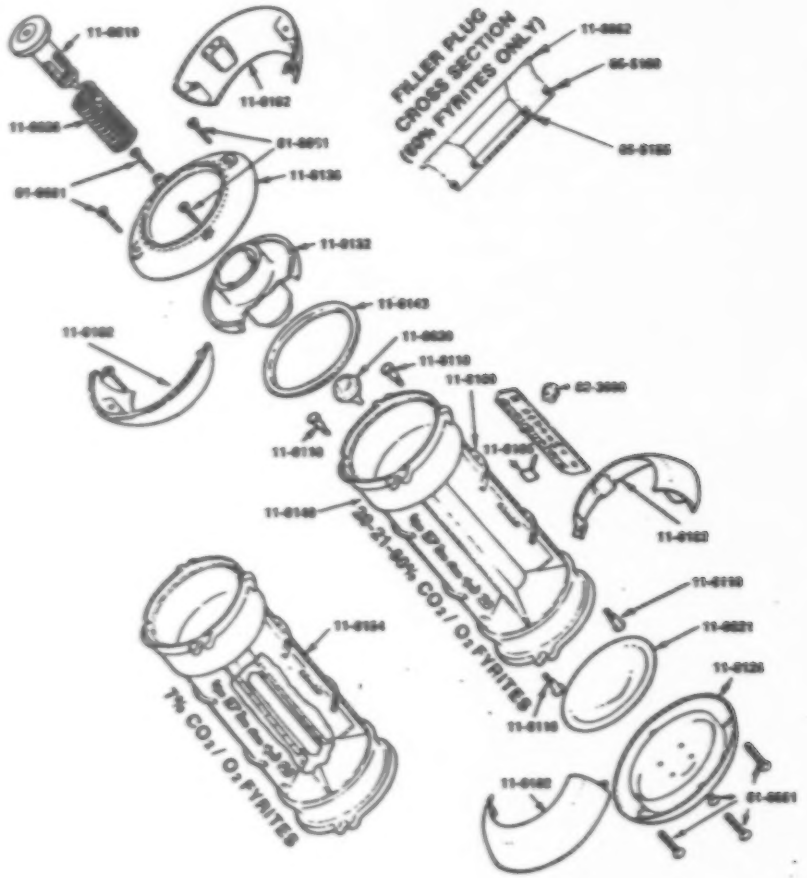
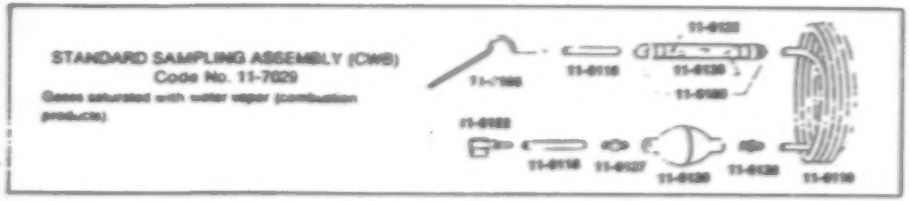
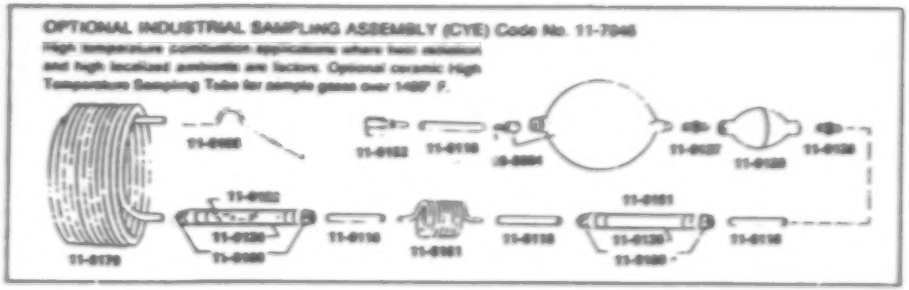
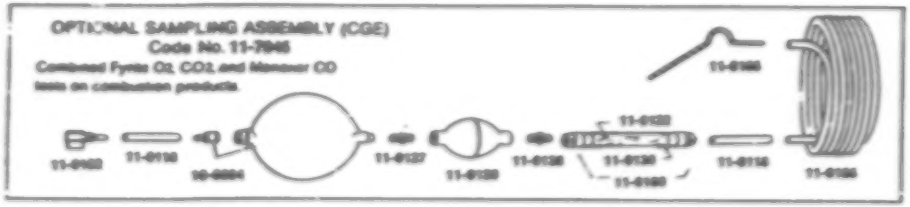


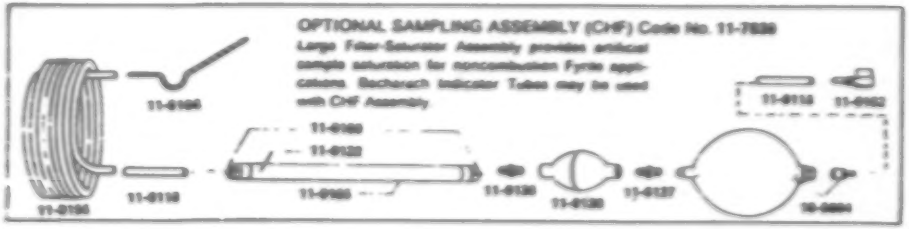
Figure 33 FYRITE Parts Breakout.

7.2 Parts List for FYRITE SAMPLING ASSEMBLIES









Current Code Number	Former List Number	Item	Number Required
11-0152	10-0018	Connector Tip with Tube	1
11-0116	10-0003	Rubber Tubing, 6" Length (4 req'd for CYE)	2
11-0127	10-0021	Outlet Valve (Green)	1
11-0128	10-0022	Aspirator Bulb	1
11-0130	10-0023	Inlet Valve (Red)	1
11-0118	10-0024	Rubber Tubing, 3" length	1
11-0180	10-0025	Filter Nipple with Bushing	2
11-0130	10-0026	Filter Tube, Plastic	1
11-0166	10-0027	Sampling Tube	1
11-0132	10-0028	Filter Packing For Filter Tube* (2 required for CHF)	1
		*For Replacement Purposes Order	
11-0121	10-0033	Envelope of Filtering Material	

Current code Number	Former List Number	Item	Number Required
11-0165	10-0029	Rubber Tubing, 10" length	1
11-0165	10-0030	Filter Tube, Aluminum	1
10-5004	10-5004	Gas Collecting Bladder with Orifice	1
11-0182	10-0031	Filter Saturator (plastic) Assembly comprising 11-0180, 11-0130 and 11-0122	
11-0181	10-0032	Filter Saturator (Aluminum) Assembly Comprising 11-0180, 11-0122, and 11-0165	
11-0161	10-0040	Condenser Coil	1
11-0151	10-0041	Moisture Trap Assembly	1
11-0179	10-0042	Rubber Tubing, 15" length	1
11-0164	10-0047	Ceramic High Temperature Gas Sampling Tube 18" length (optional)	1

Figure 1c: Venting FYRITE to atmosphere in the proper position.

Figure 1d: NEVER vent FYRITE in the inverted position, which will cause fluid spill.

APPENDIX 9

NATURAL GAS RATE SCHEDULE "A"

CANADIAN WESTERN NATURAL GAS
COMPANY LIMITED

909 - 11 AVENUE S.W.,
CALGARY, ALBERTA T2R 1L8
TELEPHONE (403) 245-7110

May 3, 1984

Monenco Consultants Ltd.
400 Monenco Place
801 - 6th Avenue S.W.
Calgary, Alberta
T2R 3W3

Attention: Scott Kestner

Dear Mr. Kestner:

Re: Natural Gas Rates

Enclosed please find copies of our latest natural gas rates. I have also included a summary of past changes and forecasted rates.

If you require any further information please contact me at 245-7199.

Yours truly,

K Hancherow

Kirk Hancherow
Marketing Representative

KH/gcs
Enclosures

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

SUMMARY OF RATE SCHEDULE "A"
All prices in Dollars per Gigajoule (GJ)

February 16, 1984

GENERAL RATE #1
Residential or Small Commercial

	Feb. 1/83	July 1/83	Aug. 1/83	Nov. 1/83 Dec. 1/83	Feb. 1/84	Mar. 1/84
ixed Charge per Month	$9.50	$9.50	$9.50	$9.50	$9.50	$9.50
otal Commodity Chg.	$2.877/GJ	$2.617/GJ	*$2.458/GJ	$2.659/GJ	$2.659/GJ	$2.570/GJ
ranchise Tax	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%
rovincial Discount · Alberta Income Tax Rebate	2.00%	5.50%	5.50%	5.50%	6.50%	6.50%

Includes: $.015 Federal Excise Tax Rider
** $.186 Excess Revenue Rider*

OPTIONAL RATE #2* (See Note #1)
Large Commercial or Small Industrial
— Applicable to customers with consumptions above 6700 GJ/year.

	Feb. 1/83	July 1/83	Aug. 1/83	Nov. 1/83 Dec. 1/83	Feb. 1/84	Mar. 1/
	$125.00	$125.00	$125.00	$125.00	$125.00	$125.0
	$2.670/GJ	$2.428/GJ**	$2.269/GJ	$2.449/GJ	$2.449/GJ	$2.360/
	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%
	1.35%	3.40%	3.40%	5.50%	6.50%	6.50%

Includes: $.015 Federal Excise Tax Rider
*** $.165 Excess Revenue Rider*

HIGH LOAD FACTOR #3* (See Note #1)
Large Industrial in Urban Areas with Process Load
Approx. 10 000GJ per year
40% from May to October Inclusive

	Feb. 1/83	July 1/83	Aug. 1/83	Nov. 1/83	Dec. 1/83	Feb. 1/84	Mar. 1/84
ixed Charge per Month	$125.00	$125.00	$125.00	$125.00	$125.00	$125.00	$125.00
emand Chg./GJ/Month laximum 12 hour demand	$ 5.50/GJ	$ 5.25/GJ	$ 5.25/GJ	$ 5.25/GJ	$ 5.25/GJ	$ 5.25/GJ	$ 5.25/GJ
l Commodity	$ 2.413	$ 2.291	*** $ 2.132	$ 2.219	$ 2.219	$ 2.219	$ 2.130/GJ
ranchise Tax	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%
ovincial Discount or lberta Income Tax Rebate	1.20%	2.40%	2.40%	2.70%	5.50%	6.50%	6.50%

Includes: $.015 Federal Excise Tax Rider
**** $.072 Excess Revenue Tax Rider*

Requires Optional Rate Contract Contract Year November 1 to October 31 (Note #1)

H.T. ANDERSEN
Phone: 245-7740

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

GENERAL CONDITIONS APPLYING TO RATES

1. Revenue and Municipal Tax Rider (Rider "A" and Rider "B")

   Rates 1 through 8, including any charges under other Riders, to customers situated within the communities listed on Riders "A" or "B" are subject to the addition of charges as shown on the applicable rider.

2. Sales not eligible for rebates (Rider "C")

   Sales not eligible for rebate under The Natural Gas Rebates Act are subject to an additional charge as shown on Rider "C" for Rates 1 through 8.

3. Late Payment Charge

   When accounts are not paid in full on or before the due date, the amount relating to the current month's charge unpaid by the due date shall be increased by 5% and the increased amount shall become due and payable.

4. In the case of short term sales agreements or if the sales have no adverse effect on the Company's load factor, the Company may waive the requirement in the Rates for "The purchase of the total requirements from the Company" from the Rates.

5. The Rates do not include extra costs incurred by the Company for special facilities or delivery conditions requested by the customer at the delivery point.

6. Annual Contract

   Where it appears on the rate schedules, the words "annual contract" shall mean the twelve-month period commencing November 1 and ending October 31.

7. Approval of Public Utilities Board

   Changes in Rates from time to time are subject to approval by the Public Utilities Board for the Province of Alberta.

8. Special Contracts

   Unless varied by the Public Utilities Board, service to customers under Special Contracts shall be subject to the terms and conditions thereof.

9. Federal Excise Tax

   The words "Federal Excise Tax", which appear in the rates, refer collectively to "Natural Gas and Gas Liquids Tax" and the "Canadian Ownership Special Tax".

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

RIDER "A" TO RATE NO. 1 TO RATE NO. 8 AND ANY OTHER RIDER THERETO

Additions to be made to the Rate of customers resident in municipalities that have agreed to accept payment of a percentage of gross revenue of the special franchise pursuant to Section 14(7) of The Municipal Taxation Act in lieu of a property tax assessed pursuant to that Act.

The percentage shown is to be applied as an addition to the total billings calculated under the Rates including charges allowed under other Riders in effect.

	Municipal Tax		Municipal Tax		Municipal Tax
Calgary	11.11**	Cowley	5.26	Lundbreck	N.A.
		Cranford	N.A.	Magrath	5.25
Lethbridge	11.11	Cremona	5.26	Milk River	5.26
		Crossfield	5.25	Monarch	N.A.
Acme	5.25	Crowsnest Pass	5.26	Morley	N.A.
Airdrie	5.25	Dalemead	N.A.	Mountain View	N.A.
Aldersyde	N.A.	Delburne	5.25	Nanaka	N.A
Banff	5.25	Dewinton	N.A.	Nanton	5.25
Barnwell	5.26	Diamond City	N.A.	Nobleford	5.25
Barons	5.25	Didsbury	5.25	Okotoks	5.25
Bassano	5.26	Duchess	5.26	Olds	6.00
Beiseker	5.25	Elnora	5.26	Parkland	N.A.
Big Valley	5.25	Enchant	N.A.	Penhold	5.25
Black Diamond	5.26	Exshaw	N.A.	Picture Butte	5.25
Bow Island	5.26	Foremost	5.26	Purple Springs	N.A.
Bowden	5.25	Fort MacLeod	5.26	Raymond	5.25
Bragg Creek	N.A.	Gem	N.A.	Rockyford	5.26
Brocket	N.A.	Gleichen	N.A.	Rosebud	N.A.
Brooks	5.25	Glenwood	5.26	Rosemary	5.26
Burdett	5.26	Granum	5.25	Seebe	N.A.
Canmore	5.25	Grassy Lake	5.26	Shaughnessy	N.A.
Carbon	5.25	Harvey Heights	N.A.	Shepard	N.A.
Cardston	5.25	High River	5.26	Spring Coulee	N.A.
Carmangay	5.25	Hill Spring	5.26	Standard	5.26
Carseland	N.A.	Hussar	5.26	Standoff	N.A.
Carstairs	5.25	Huxley	N.A.	Stavely	5.25
Cayley	5.26	Indus	N.A.	Stirling	5.25
Cessford	N.A.	Innisfail	5.25	Strathmore	1.0*
Champion	5.25	Iron Springs	N.A.	Swalwell	N.A.
Cheadle	N.A.	Irricana	5.25	Taber	5.26
Chestermere Lake	N.A.	Kathyrn	N.A.	Torrington	5.25
Clarasholm	5.25	Keoma	N.A.	Trochu	5.26
Cluny	N.A.	Kirkcaldy	N.A.	Turin	N.A.
Coaldale	5.26	Lac-Des-Arcs	N.A.	Turner Valley	5.25
Coalhurst	5.26	Langdon	N.A.	Vauxhall	5.25
Cochrane	5.26	Linden	5.25	Vulcan	.5*
Conrich	N.A.	Lamond	5.26	Welling	N.A.
		Longview	5.25	Wimborne	N.A.

N.A. Not Applicable

* Rider B

** Exclusive Cowley Plant 3.00%

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

RIDER "B" TO RATE NO. 1 TO RATE NO. 8 AND ANY OTHER RIDERS THERETO

Additions to be made to the Rate of customers resident in municipalities that receive a property tax assessed under the Municipal Taxation Act. The addition is the estimated percentage of gross revenue required to provide for the tax payable each year. To the extent that this percentage may be more or less than that required to pay the tax, the percentage of gross revenue provided in the Rider will be adjusted on the 1st of February each year to the nearest 0.5% following approval of such change by the Public Utilities Board.

The percentage shown is to be applied as an addition to the total billings calculated under the Rates including charges allowed under other Riders in effect.

Municipality	Percentage	
Strathmore	Town	1.0%
Vulcan	Town	1.5%

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

RIDER "C" TO RATE NO.1 TO RATE NO.8

FOR "NON-REBATEABLE SALES", THAT IS, SALES NOT SUBJECT TO REBATE UNDER THE NATURAL GAS REBATES ACT

The Energy Charge on "non-rebateable sales" shall be increased by:

$0.616 per gigajoule

Revenue from the above rate is subject to reconciliation based on actual provincial rebates received under The Natural Gas Rebates Act.

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

RATE NO. 1 - GENERAL SERVICE RATE

Available to all customers except those customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency service.

Fixed Charge:	$9.50 per Month
Plus Energy Charge:	
Base	$2.480 per GJ
Federal Excise Tax	$0.062 per GJ
Energy Charge	$2.542 per GJ

The Energy Charges shown above shall be increased by the following revenue deficiency rider for consumption from March 1, 1984 to November 30, 1984 inclusive:

Base	$0.028 per GJ

Minimum Monthly Charge: Fixed Charge

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

RATE NO. 2 - OPTIONAL GENERAL SERVICE - LARGE USE RATE

Available to all customers on an annual contract except those customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency service.

Fixed Charge	$125.00 per Month
Plus Energy Charge:	
Base	$2.270 per G
Federal Excise Tax	$0.062 per G
Energy Charge	$2.332 per G

The Energy Charges shown above shall be increased by the following revenue deficiency rider for consumption from March 1, 1984 to November 30, 1984 inclusive:

Base	$0.028 per G

Minimum Monthly Charge: Fixed Charge

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED

RATE NO. 3 - OPTIONAL GENERAL SERVICE - HIGH LOAD FACTOR RATE

Available to all customers on an annual contract except those customers who do not purchase their total natural gas requirements from the Company or who utilize the Company's facilities only for standby, peaking or emergency service.

Fixed Charge:	125.00 per Month plus $5.25 per Month per GJ of Billing Demand
Plus Energy Charge:	
Base	$2.040 per GJ
Federal Excise Tax	$0.062 per GJ
Energy Charge	$2.102 per GJ

The Energy Charges shown above shall be increased by the following revenue deficiency rider for consumption from March 1, 1984 to November 30, 1984 inclusive:

Base	$0.028 per GJ

Minimum Monthly Charge: Fixed Charge

Minimum Annual Charge:

The minimum annual charge shall be calculated after the end of each contract year, and shall be the greater of:

1. the sum of the fixed charges plus the energy charges for the contract year, or

2. the sum of:

   the number of GJ, if any, by which two-thirds of the customer's winter period consumption exceeds the customer's summer period consumption times the difference between the customer's weighted average Energy Charge per GJ for the summer period and $0.25 per GJ

   AND

   the sum of the customer's fixed charges plus the energy charges for the contract year.

Determination of Billing Demand:

The Billing Demand shall be the greater of:

1. 35 GJ or

2. the greatest amount of gas in GJ delivered in any consecutive 12-hour period during the current and preceding eleven billing periods provided that the greatest amount of gas delivered in any 12 consecutive hours in the summer period shall be divided by 2, or

3. the Nominated Demand

PROVIDED that for a customer who elects to take service only during the summer period, the Billing Demand for each billing period shall be the greatest amount of gas in GJ in any consecutive 12 hours in that billing period.

In the first contract year, the Company shall estimate the Billing Demand from information provided by the customer.

Nominated Demand:

A customer whose maximum consumption exceeds 2 500 GJ for any 12-hour period in the winter period must nominate in writing twelve months in advance of each contract year the maximum consumption for any 12-hour period in the winter period in that contract year (the "Nominated Demand"). The Company reserves the right to restrict the amount of gas in GJ delivered in the winter period to the Nominated Demand and to restrict the amount of gas in GJ delivered in any one hour to 10% of the Nominated Demand.

Winter Period - Summer Period:

The winter period is the six meter reading periods ending in the period from November 1 to April 30 and the summer period is the six meter reading periods ending in the period from May 1 to October 31.

Canadian Western Natural Gas Company Limited

FORECAST NATURAL GAS COSTS

RESIDENTIAL CUSTOMERS (200 GJ PER YEAR)
1983-1989

GENERAL RATE		1983 Average Rate	1984 Actual Jan. 1st	1984 Actual Feb. 1st	1984 Actual March 1st	1984 Forecast Dec. 1st	1984 Average Rate	1985 Forecast Jan. 1st	1985 Forecast April 1st	1985 Average Rate	1986 Forecast Jan. 1st	1986 Forecast April 1st	1986 Average Rate	1987 Forecast Average	1988 Forecast Average	1989 Forecast Average
Fixed Charge per Month	$	9.50	9.50	9.50	9.50	9.50	9.50	10.00	10.00	10.00	10.50	10.50	10.50	11.00	11.55	12.00
Basic Energy Charge	$/GJ	.744	.713	.713	.713	.713	.713	.749	.749	.749	.786	.786	.786	.825	.867	.910
Gas Supply Costs	$/GJ	1.550	1.666	1.666	1.767	1.767	1.737	1.767	2.087	1.952	2.087	2.857	2.537	3.228	3.993	4.565
Federal Excise Tax	$/GJ	.373	.140	.140	-	-	.041	-	-	-	-	-	-	-	-	-
Canadian Ownership Tax	$/GJ	.140	.140	.140	.062	.062	.095	.140	.140	.075	-	-	-	-	-	-
Deficiency Rider	$/GJ	.007	-	-	.028	-	.017	-	-	-	-	-	-	-	-	-
Deficiency Rider	$/GJ	(.029)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F.E.T. Rider	$/GJ	(.003)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Energy Cost	$/GJ	2.792	2.659	2.659	2.570	2.542	2.593	2.656	2.976	2.841	2.873	3.653	3.323	4.045	4.860	5.475
Municipal Tax	%	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11
Income Tax Rebate	%	3.23	5.50	6.50	6.50	6.50	6.349	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
Annual Cost																
Annual Cost	$	723	682	675	657	651	662	681	749	719	732	896	827	984	1 161	1 296
Average Cost Per GJ	$/GJ	3.648	3.410	3.378	3.285	3.256	3.314	3.406	3.741	3.599	3.664	4.480	4.135	4.921	5.808	6.480
Percentage Increase	%	-	-	-	(1.0)	(2.8)	-	-	-	9.8	-	-	27.1	-	-	-	-
Percentage Increase Over Previous Year	%	9.4	-	-	-	-	(8.4)	-	9.8	8.7	-	-	14.9	19.0	18.0	11.6

1) Gas Supply Cost Based on National Energy Program Update 1983.
2) Company's cost of Service increased at 5% per year during forecast period.
3) Assumes C.O.T. to the end of 1985.
4) Average Rates are based on Monthly %'s of Annual Consumption.

MARCH, 1984

Canadian Western Natural Gas Company Limited

Section No. 3
Sheet No. 2

FORECAST NATURAL GAS COSTS

COMMERCIAL CUSTOMERS (10 000 GJ PER YEAR)
1983-1989

OPTIONAL RATE		1983 Average Rate	1984 Actual Jan. 1st	1984 Actual Feb. 1st	1984 Actual March 1st	1984 Forecast Dec. 1st	1984 Average Rate	1985 Forecast Jan. 1st	1985 Forecast April 1st	1985 Average Rate	1986 Forecast Jan. 1st	1986 Forecast April 1st	1986 Average Rate	1987 Forecast Average	1988 Forecast Average	1989 Forecast Average
Fixed Charge per Month	$	125.00	125.00	125.00	125.00	125.00	125.00	131.00	131.00	131.00	138.00	138.00	138.00	145.00	152.00	160.00
Basic Energy Charge	$/GJ	.533	.503	.503	.503	.503	.503	.528	.528	.528	.554	.554	.554	.582	.611	.642
Gas Supply Costs	$/GJ	1.566	1.666	1.666	1.767	1.767	1.739	1.767	2.087	1.959	2.087	2.867	2.555	3.233	3.998	4.570
Federal Excise Tax	$/GJ	.360	.140	.140	-	-	.039	-	-	-	-	-	-	-	-	-
Canadian Ownership Tax	$/GJ	.140	.140	.140	.062	.062	.083	.140	.140	.140	-	-	-	-	-	-
Deficiency Rider	$/GJ	.008	-	-	.028	-	.012	-	-	-	-	-	-	-	-	-
Deficiency Rider	$/GJ	(.012)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
F.E.T. Rider	$/GJ	(.003)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Energy Cost	$/GJ	2.582	2.449	2.449	2.360	2.332	2.376	2.435	2.755	2.627	2.641	3.421	3.109	3.815	4.609	5.212
Municipal Tax	%	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11
Income Tax Rebate	%	2.62	5.50	6.50	6.50	6.50	6.35	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
Annual Cost																
Annual Cost	$	29 637	27 448	27 188	26 257	25 964	26 471	27 117	30 465	29 126	29 360	37 519	34 256	41 739	50 123	56 531
Average Cost Per GJ	$/GJ	2.964	2.7448	2.719	2.626	2.596	2.647	2.712	3.047	2.913	2.936	3.752	3.426	4.174	5.012	5.653
Percentage Increase	%	-	-	-	(0.95)	(3.4)	(1.1)	-	-	12.3	-	-	29.5	-	-	-	-
Percentage Increase Over Previous Year	%	5.6	-	-	-	-	(10.7)	-	-	10.0	-	-	17.6	21.8	20.0	12.7

1) Gas Supply Cost Based on National Energy Program Update 1983.
2) Company's cost of Service increased at 5% per year during forecast period.
3) Assumes C.O.T. to the end of 1985.
4) Average Rates are based on Monthly %'s of Annual Consumption.
5) Assumes P.S.P. to phase out by April 1st, 1985.

REVISED MARCH, 1984

Section No.
Sheet No.

Canadian Western Natural Gas Company Limited

FORECAST NATURAL GAS COSTS

INDUSTRIAL CUSTOMER (50 000 GJ PER YEAR & DEMAND OF 100 GJ PER 12 HRS.)

1983-1989

		1983	1984				1985			1986			1987	1988
		Average Rate	Actual Jan. 1st	Actual Feb. 1st	Actual March 1st	Forecast Dec. 1st	Average Rate	Forecast Jan. 1st	Forecast April 1st	Average Rate	Forecast Jan. 1st	Forecast April 1st	Average Rate	Forecast Average	Forecast Average
H.L.F. RATE															
Fixed Charge per Month	$	125.00	125.00	125.00	125.00	125.00	125.00	131.00	131.00	131.00	138.00	138.00	138.00	145.00	152.00
Demand Charge		5.36	5.25	5.25	5.25	5.25	5.25	5.50	5.50	5.50	5.80	5.80	5.80	6.10	6.40
Basic Energy Charge	$/GJ	.286	.273	.273	.273	.273	.273	.287	.287	.287	.301	.301	.301	.316	.332
Gas Supply Costs	$/GJ	1.570	1.666	1.666	1.767	1.767	1.750	1.767	2.087	2.003	2.087	2.867	2.663	3.319	3.926
Federal Excise Tax	$/GJ	.336	.140	.140	-	-	.021	-	-	-	-	-	-	-	-
Canadian Ownership Tax	$/GJ	.140	.140	.140	.062	.062	.075	.140	.140	.140	-	-	-	-	-
Deficiency Rider	$/GJ	.009	-	-	.028	-	.021	-	-	-	-	-	-	-	-
Deficiency Rider	$/GJ	(.027)	-	-	-	-	-	-	-	-	-	-	-	-	-
F.E.T. Rider	$/GJ	(.006)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Energy Cost	$/GJ	2.308	2.219	2.219	2.130	2.102	2.143	2.194	2.514	2.430	2.388	3.168	2.964	3.634	4.258
Municipal Tax	%	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11	11.11
Income Tax Rebate	%	2.25	5.50	6.50	6.50	6.50	6.40	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
Annual Cost															
Annual Cost	$	134 285	125 412	124 224	119 569	118 103	120 368	123 290	140 028	135 649	133 918	174 715	164 044	199 552	232 65
Average Cost Per GJ	$/GJ	2.686	2.508	2.484	2.391	2.362	2.407	2.466	2.801	2.713	2.678	3.494	3.281	3.991	4.65
Percentage Increase	%	-	-	(0.95)	3.8	(1.2)	-	-	-	13.6	-	-	32.660	-	
Percentage Increase Over Previous Year	%	3.2	-	-	-	-	(10.4)	-	-	12.7	-	-	20.9	21.6	16

1) Gas Supply Cost Based on National Energy Program Update 1983.
2) Company's cost of Service increased at 5% per year during forecast period.
3) Assumes C.O.T. to the end of 1986.
4) Average Rates are based on Monthly %'s of Annual Consumption.

MARCH, 1984

APPENDIX 10

STEAM PRODUCTION FIGURES 1982/83

TO :- R.KINNEE

STEAM PRODUCTION FIGURES

	1982 STEAM 1000 LBS	1982 GAS USAGE G.JOULES	1983 STEAM 1000 LBS	1983 GAS USAGE G.JOULES
JAN	31355	58912	31538	54696
FEB	32192	40863	33377	40516
MAR	37648	52625	39000	53895
APR	28132	38931	27780	39783
MAY	27152	50668	28518	49721
JUN	42676	40247	33353	38527
JUL	23679	42132	26661	34335
AUG	21075	29319	21636	29286
SEPT	33255	35339		
OCT	26833	20645		
NOV	31441	50561		
DEC	36600	42860		
1982	31355	503102	1983 241863	340759

NOTE:- IN 1982 A HIGH NUMBER OF STEAM PRODUCTION FIGURES WERE ESTIMATED.
GAS USAGE IS TOTAL PLANT USAGE. STEAM PLANT COSTS ARE ESTIMATED TO BE 75 % OF TOTAL USAGE.
THERE IS A TIMING DIFFERENCE BETWEEN STEAM PRODUCTION FIGURES AND GAS CONSUMPTION PER THE UTILITY INVOICES.

REVISED STEAM PRODUCTION FIGURES.
i.e. 75% total usage.

	1982 STEAM	1982 GAS	1983 STEAM	1983 GAS
JAN	31355	44184	31538	41022
FEB	32192	30647	33377	30387
MAR	37648	39469	39000	40421
APR	28132	29198	27780	29837
MAY	27152	38001	28518	37291
JUN	42676	30185	33353	28895
JUL	23679	31599	26661	25751
AUG	21075	21989	21636	21965
SEPT	33255	26504		
OCT	26833	15484		
NOV	31441	37921		
DEC	36600	32145		
1982	31355	377327	241863	255569

POOR

QUALITY

ORIGINAL